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MINERALS MANAGEMENT SERVICE

CONTRACT NO. 1435-01-CT-99-50001
APPRAISAL AND DEVELOPMENT OF PIPELINE DEFECT ASSESSMENT METHODOLOGIES

FINAL REPORT PHASES I & II

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EXECUTIVE SUMMARY

MSL Engineering Limited (MSL) has prepared this report for the United States Minerals Management Service (MMS) in relation to the project entitled 'Appraisal and Development of Pipeline Defect Assessment Methods'.

Objectives and Scope of Work

A variety of analytical tools are available for the assessment of pipeline defects. The objective of this project was to identify the various methods and to evaluate their application to, and their efficiency in, assessing the safety of offshore pipelines with geometric and material defects. The primary tasks undertaken to meet the project objectives were as follows:

i) **Collation, review and appraisal of pipeline defect related literature**, including codes, standards, published reports and technical papers.

ii) **Interviews with major international pipeline operating companies** and an appraisal of current industry practice for pipeline inspection and defect assessment.

iii) **Development of a database** of screened test results for different defect forms including corrosion defects, mechanical damage and girth-weld defects.

iv) **Evaluation of defect assessment methods**, by comparison of test results with predicted results, for pipeline corrosion defects, mechanical damage and girth-weld defects.

Conclusions

The following main conclusions can be drawn from the tasks carried out in the study.

i) Literature

- Almost 400 references were sourced for this study.
- A review of accident and incident statistics showed that during the period 1984-1998, there was no apparent decrease in the number of events with time. There are some regional differences as to the cause of pipeline defects, e.g. corrosion is the most common cause in the Gulf of Mexico whilst third party actions top the list in the North Sea.
- Many references contain data on burst pressure tests on damaged pipelines, particularly for corrosion damage.
- A variety of codified assessment approaches were identified, the background of some being further detailed in the technical references.

ii) Interviews with Operators

- Interviews were held in the USA, UK and Norway.
- European interviewees reported very few problems had been experienced with their pipelines. This was thought to reflect benign sweet gas conditions.
- In-service anomalies found during inspections were mostly related to internal corrosion.
- It would appear that the imposition of high standards of inspection during pipeline manufacture is cost effective. One operator has gone even further in stipulating stricter (than code) requirements on steel chemistry (to improve weldability) and dimensions (to facilitate fabrication).
- The recommendations of ASME B31G are commonly used for defect assessment in the US. These were generally believed to be conservative.
- Construction activity was felt to present a significant risk of damage to existing and new pipelines.
- External corrosion is not, generally, believed to be a problem for pipelines in the Gulf of Mexico. The sacrificial anode system has been shown to provide successful lifetime protection against external corrosion.

iii) Database development

- Data was collected and screened for over 800 test specimens, these being categorized into defect types as follows:
  - Corrosion defects (70%)
  - Mechanical damage (15%)
  - Girth weld defects (15%)
- The data were entered into a spreadsheet for comparisons against various predictive methods.

iv) Evaluation of assessment methods

- Based on analysis of the girth weld defects database, API 1104 appears to be the simplest method while remaining reasonably conservative. The R/H/R6 Category 1 appears to be slightly more conservative than BS 7910 Level 2 with flat plate stress intensity factors. Less conservative predictions are obtained with BS 7910 when the curved shell rather than the flat plate stress intensity factors are invoked.
- Based on analysis results of the corrosion defect database, the DNV RP-F101 method was shown to be more conservative than either the ASME B31G or the

RSTRENG methods. However, in terms of the coefficient of variation, the DNV RP-F101 method proved to be the most accurate of the three methods examined, and the ASME B31G was shown to be the least accurate of the methods.

- In regard to mechanical damage defects, the PRCI's DFGM appears to be a good model for predicting failure. The comparison of this method to test data would require the development of numerical models of the dents with due account for material and geometrical non-linearity. Such FE modeling is beyond the scope of this project.

1. INTRODUCTION

1.1 General

Offshore pipelines transport large quantities of oil and gas vital to our global economy. Any failure to ensure the safe and continuous operation of these pipelines may have serious economic, environmental and life-safety implications. A prerequisite to pipeline safe operation is assurance of structural integrity to a high level of reliability throughout their lives. Such integrity may be threatened by defects introduced into the pipeline system during fabrication, installation or operation. Since it is impractical to prevent all defects from occurring and because not all defects are harmful to pipeline integrity, it is essential to be able to distinguish defects that can be tolerated from those that cannot.

A variety of analytical tools are available for the assessment of pipeline defects. The objective of this project was to identify the various methods and to evaluate their application to, and their efficiency in, assessing the safety of offshore pipelines with geometric and material defects. The scope of work executed to meet the project objectives can be summarized as follows:

- **Collation, review and appraisal of pipeline defect related literature**, including codes, standards, published reports and technical papers.

- **Interviews with major international pipeline operating companies** and an appraisal of current industry practice for pipeline inspection and defect assessment.

- **Development of a database** of screened test results for different defect forms including corrosion defects, mechanical damage and girth-weld defects.

- **Evaluation of defect assessment methods**, by comparison of test results with predicted results, for pipeline corrosion defects, mechanical damage and girth-weld defects.

1.2 Background

A number of studies on the failure and/or loss of containment of pipelines have been conducted based on statistical analysis of information usually held by regulatory authorities or pipeline operators. These studies provide an indication of the level of reliability achieved in the operation of pipelines. They also provide information on the frequency of pipeline failure and the potential causes and modes of failure. This information can be correlated to pipeline parameters such as location, contents, geometry, material etc. to identify trends in pipeline failures, providing useful feedback for future design, fabrication, maintenance and inspection.

Some recent published studies on pipeline failures include:

- Mandke - evaluation of failure rate data for the Gulf of Mexico using the database of the US Minerals Management Service (MMS). This study covered 690 incidents that occurred during the Period 1967 to 1987. Information from 1987 onwards is not currently available.

- HSE/UKOOA commissioned a number of studies of pipeline failures in the North Sea. Some results from these studies are reported by Williams et al covering the period up to 1989. The HSE (PARLOC) has released further reports covering periods 1989 to 1992 and 1992 to 1994. Findings from 1994 to 1996 have been released recently by the HSE.

- The Office of Pipeline Safety (OPS) of the US Department of Transport (DOT) collected all pipeline incident data from 1968-1999.

Comparison of Gulf of Mexico (Mandke) and North Sea Pipeline failure studies indicated that the primary cause of failures listed in decreasing frequency of occurrence/detection were as follows:

Gulf of Mexico: Corrosion, third party, storm and slides, material and equipment failure.

North Sea: Third party, corrosion, material failure.

Data extracted from the database of the Office of Pipeline Safety, on incident and accident statistics for the period covering 1984-1998, is presented in Table 1.1 for hazardous liquids and gas transportation/distribution. It can be observed from Table 1.1 that the number of incidents and accidents show no apparent decrease with time. The primary causes for pipeline related incidents are presented in Tables 1.2 to 1.4. The causes shown in the tables, listed in decreasing frequency of occurrence, include:

- Damage from outside forces (i.e. mechanical damage)
- Corrosion (internal and external)
- Defective weld and pipe
- Construction/material

Further statistical data is also available e.g. MMS Hurricane Andrew and HSE PARLOC updates, which draw similar conclusions as to the causes of pipeline incidents and failure.

Year	Hazardous Liquid Pipeline Operators			Natural Gas Pipeline Operators Transmission			Natural Gas Pipeline Distribution		
	No. of Incidents	Fatalities	Injuries	No. of Incidents	Fatalities	Injuries	No. of Incidents	Fatalities	Injuries
1984	186	0	17	NA	NA	NA	NA	NA	NA
1985	183	5	18	NA	NA	NA	NA	NA	NA
1986	209	4	32	83	6	20	142	29	104
1987	237	3	20	70	0	15	164	11	115
1988	193	2	19	89	2	11	201	23	114
1989	163	3	38	103	22	28	177	20	91
1990	180	3	7	89	0	17	109	6	52
1991	216	0	9	71	0	12	162	14	77
1992	212	5	38	74	3	15	103	7	65
1993	230	0	10	96	1	18	121	16	84
1994	243	1	7	81	0	22	141	21	91
1995	188	3	11	64	2	10	97	16	43
1996	195	5	13	77	1	5	110	47	109
1997	175	0	5	73	1	5	108	10	83
1998	151	1	2	96	1	10	132	16	62

Table 1.1: Offshore Pipeline Safety Summary of Incident/Accident Statistics by Year

Cause	Year				
	1994	1995	1996	1997	1998
Internal Corrosion	0 (0)	0 (0)	1 (0.92)	0 (0)	0 (0)
External Corrosion	5 (3.55)	3 (3.09)	1 (0.92)	3 (2.78)	5 (3.79)
Damage From Outside Forces	79 (56.03)	66 (68.04)	64 (58.72)	59 (54.63)	86 (65.15)
Construction/ Operating Error	13 (9.22)	5 (5.15)	6 (5.50)	4 (3.70)	5 (3.79)
OPERATOR ERROR	10 (7.09)	6 (6.19)	6 (5.50)	6 (5.56)	8 (6.06)
Other	34 (24.11)	17 (17.53)	21 (19.27)	36 (33.33)	28 (21.21)
Total	141	97	109	108	132

Note: Values in Bracket indicate % of total incidents

Table 1.2: Office of Pipeline Safety – Gas Distribution Pipeline Accident Summary by Cause

Cause	Year				
	1994	1995	1996	1997	1998
Internal Corrosion	20 (25)	5 (7.81)	6 (8.22)	16 (23.88)	13 (13.54)
External Corrosion	13 (16.25)	4 (6.25)	7 (9.59)	5 (7.46)	7 (7.29)
Damaged From Outside Forces	23 (28.75)	27 (42.19)	37 (50.68)	28 (41.79)	36 (37.50)
Constructional/ Material/Defect	9 (11.25)	13 (20.31)	7 (9.59)	8 (11.94)	19 (19.79)
Other	15 (18.75)	15 (23.44)	16 (21.42)	10 (14.93)	21 (21.88)
Total	80	64	73	67	96

Note: Values in Bracket indicate % of total incidents

Table 1.3: Office of Pipeline Safety – Transmission and Gathering Pipeline Accident Summary by Cause

Cause	Year				
	1994	1995	1996	1997	1998
Internal Corrosion	10 (4.1)	13 (6.81)	21 (10.99)	18 (10.2)	19 (12.5)
External Corrosion	38 (15.57)	21 (12.04)	38 (19.90	34 (19.4)	17 (11.2)
Defective Weld	21 (8.61)	9 (4.71)	9 (4.71)	3 (1.7)	7 (4.6)
Incorrect Operation	8 (3.28)	26 (13.61)	11 (5.76)	11 (6.2)	7 (4.6)
Defective Pipe	11 (4.51)	14 (7.33)	9 (4.71)	11 (6.2)	6 (3.9)
Outside Damage	57 (23.36)	54 (28.27)	48 (25.13)	40 (22.8)	40 (26.4)
Malfunction of Equipment	22 (9.02)	5 (2.62)	6 (3.14)	7 (4.0)	9 (5.9)
Other	77 (31.56)	47 (24.61)	49 (25.65)	51 (29.1)	46 (30.4)
Total	244	191	191	175	151

Note: Values in Bracket indicate % of total incidents

Table 1.4: Office of Pipeline Safety – Hazardous Liquid Pipeline Accident Summary by Cause

1.3 Definition of Defects

A defect is a material or geometric discontinuity or irregularity that is detectable by inspection in accordance with the requirements of the applicable codes and standards. Different codes and standards give different warranty of rejection of defects. A non-acceptable defect is an imperfection of sufficient magnitude to warrant rejection based on the requirements of the code, standard or other method used for the assessment of that defect.

Pipeline defects can be grouped into three categories according to their cause, namely, corrosion defects, mechanical damage and weld defects.

Corrosion Defects

Corrosion defects can be subdivided according to their nature as indicated below. Examples of each type of corrosion defect are illustrated in Figures 1.1 and 1.2.

General Corrosion:	Uniform or gradually varying loss of the wall thickness over an extended area.
Localized Corrosion Pitting:	Localized corrosion pitting can reduce the wall thickness to be less than the design thickness.
Sulphide Stress Corrosion Cracking:	Occurs primarily in steels at a region subjected to tensile stress including residual stress.
Hydrogen Stress Corrosion Cracking:	Occurs at low stresses or even in the absence of stresses or under external compressive stresses.

Mechanical Damage

Similarly, mechanical damage defects have been categorized as presented below. Examples of each type are illustrated in Figures 1.1 and 1.2.

Dent:	A depression caused by an event that produces a visible disturbance in the curvature of the wall of the pipe or component without reducing the wall thickness.
Gouge:	A surface imperfection caused by mechanical removal or displacement of metal that reduces the wall thickness of the pipe.
Groove:	A groove can cause stress concentration at the point and may be considered a defect.
Surface cracks:	Pipe body surface cracks shall be considered defects.

Weld Defects

A variety of weld defects may exist as described below.

Arc Burn	A localized condition or deposit that is caused by an electric arc and consists of re-melted metal, heat-affected metal, a change in the surface profile, or a combination thereof.
Incomplete Penetration:	The root head of weld does not completely fill the root of the joint.
Incomplete Fusion:	There is lack of bond between the weld metal and the base metal at the root or top of the joint.

Internal Concavity:	Incomplete filling of the joint.
Undercut:	A groove melted into the base metal adjacent to a weld toe at the root or top of the joint.
Slag Inclusions:	Non-metallic solid entrapped in the weld metal or between the weld metal and the base metal.
Hollow Bead:	Linear porosity or cylindrical gas pockets occurring in the root bead.

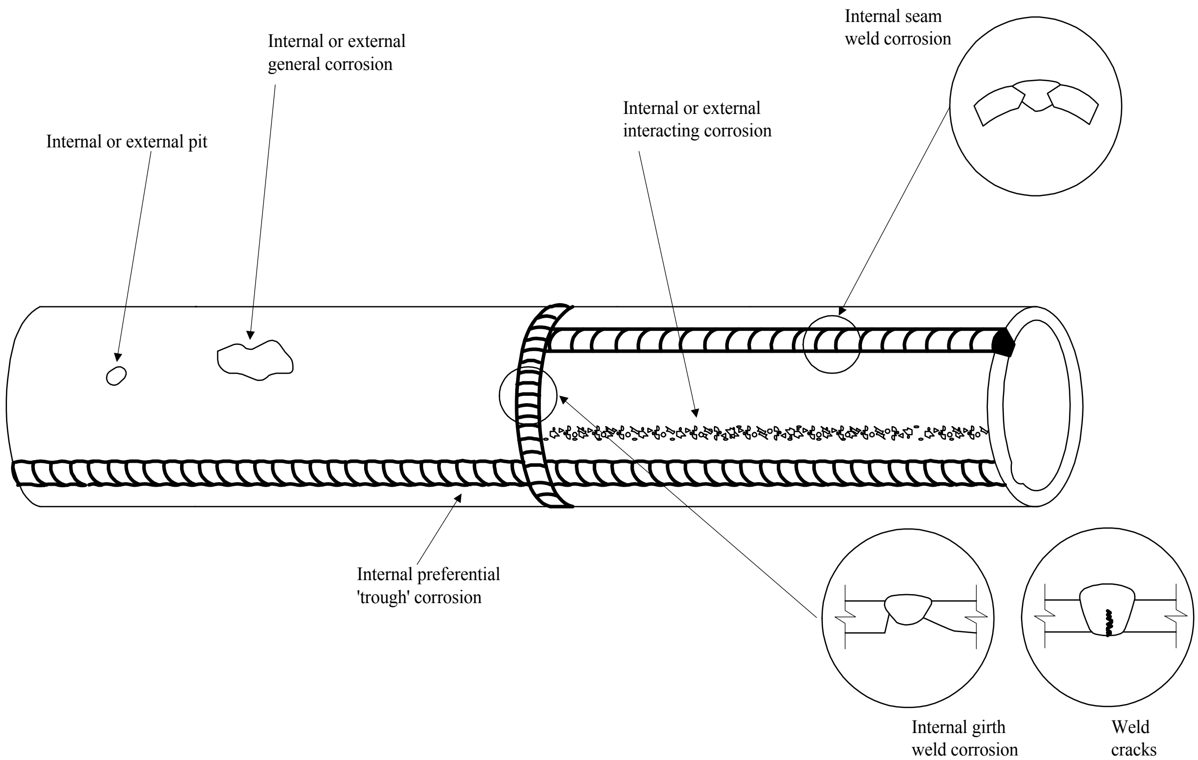

Figure 1.1: Some types of corrosion and cracking found in pipelines

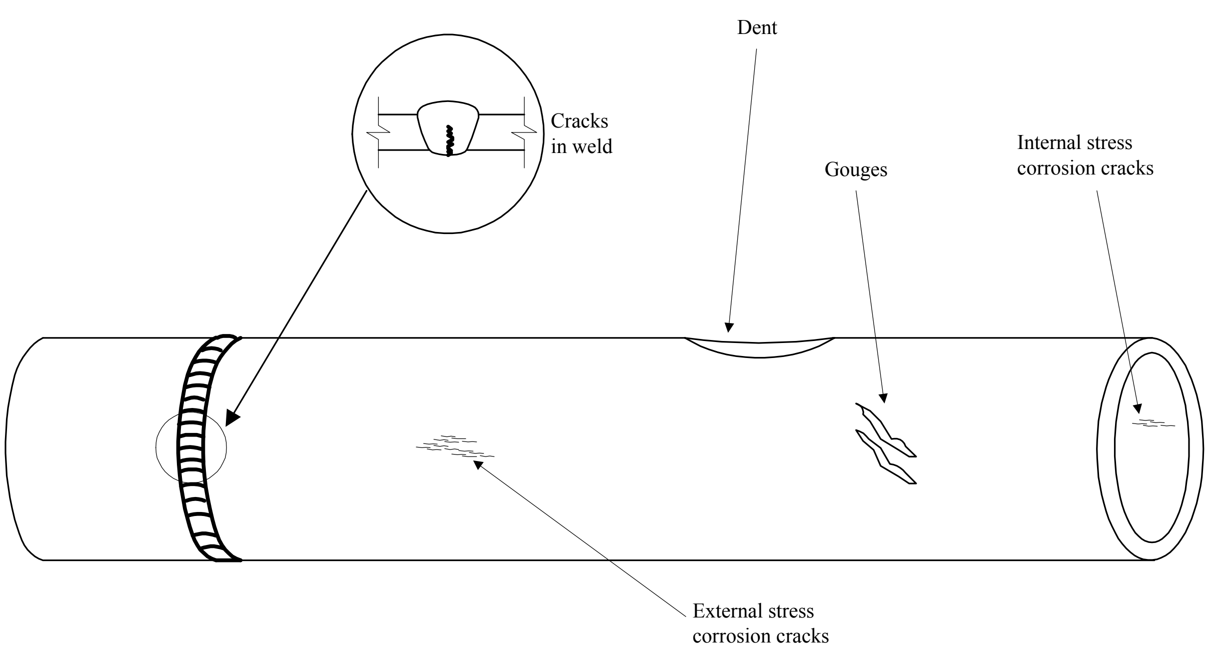

Figure 1.2: Mechanical damage and cracks found in pipelines

2. DATA CAPTURE

2.1 Literature

2.1.1 Methodology

The basic literature survey was the first task conducted in the project. There is a significant amount of literature on pipeline defect assessment and inspection techniques. To facilitate the process the literature search was undertaken in three categories. Category I included codes and standards on offshore pipeline design and defect assessment. Category II included technical papers relating to defect assessment methodologies. Category III included available technical reports from national governments and private industry. The reference sources are identified in Section 2.1.2.

The resulting literature database includes approximately 400 references. For each reference the following information has been recorded: Reference number, title, author(s), organization, date of publication, document type (i.e. conference paper, code, etc.). In addition, to enable searching of the database to be undertaken more efficiently, particularly in identifying those references that contain defect data, a 'key word' system was adopted (e.g. defect assessment, code, corrosion defect, mechanical damage, weld defect, material, inspection).

In this project, the emphasis was confined to offshore pipeline defect assessment and in particular to those types of defect damage which commonly occur. The range of defect types is presented in Section 1.3.

2.1.2 Reference Sources

The following lists of reference sources were identified:

General Design Codes and Standards:

- Pipeline Transportation System for Liquid Hydrocarbons and other Liquids, ASME B31.4, 1998, US
- Gas Transmission and Distribution Piping Systems, ASME B31.8, 1995, US
- Code of Practice for Pipelines, BSI 8010, Part3, 1993, UK
- Oil and Gas Pipeline Systems, CAS-Z662-99, 1999, Canada
- Rules for Submarine Pipeline Systems, DnV 1996, 1996, Norway
- Rules for Subsea Pipelines and Risers, GL 1995, Germany

- Pipeline Transportation System for the Petroleum and Natural Gas Industries, ISO 13623, 1996

- Design, Construction, Operation, and Maintenance of Offshore Hydro Carbon Pipeline (Limit State Design), API Recommended Practice 1111, 3rd Edition, 1999.

- Design of Long Distance Transmission Pipelines, SniP2.05.06-85, 1985, Russian

Codes and Standards on Pipeline Defect Assessment:

- Corroded Pipelines, DNV Recommended Practice RP-F101, 1999.

- Welding of Pipelines and Related Facilities, API - 1104, 1994, US

- Pipeline Maintenance Welding Practices, API – 1107, 1991, US

- Manual for Determining the Remaining Strength of Corroded Pipelines, ASME B31G, 1991, US

- Guide on Methods for Assessing the Acceptability of Flaws in Structures, BS 7910, 1999, UK

- Specification for Welding of Steel Pipelines on Land and Offshore, BS 4515, 1996, UK

- Assessment of the Integrity of Structures Containing Defects, R/H/R6 Revision 3, 1997, Nuclear Electric, UK

- Oil and Gas Pipeline Systems, CSA-Z662-99, 1999, Canada

Each of the following organizations are represented in the codes and standards identified above.

API	American Petroleum Institute, USA
ASME	American Society of Mechanical Engineers, USA
BSI	British Standards Institution, UK
CEGB	Central Electricity Generating Board, UK
CSA	Canadian Standards Association, Canada
GL	Germanischer Lloyd, Germany
ISO	International Standards Organization

A primary source of information and data relating to offshore pipeline defect assessment is technical papers presented at industry-specific conferences and seminars. The following conferences and seminars are represented in the literature database.

- Offshore Technology Conference, API, 1985 – 1999
- International Pipeline Conference, ASME, 1996, 1998
- International Conference on Offshore Mechanics and Arctic Engineering, ASME, 1990 – 1998
- International Pressure Vessel Technology Conference, ASME 1990-1998
- Pressure and Piping Conference, ASME 1990 –1998
- International Offshore and Polar Engineering Conference, ISOPE, 1997, 1998
- API Pipeline Conference, API, 1990-1998
- Pipeline Engineering Symposium, ASME, 1985-1990
- Pipeline Engineering, ASME, 1991-1995
- International Conference on Pipeline Protection, MEP, 1991-1997
- Advances in Subsea Pipeline Engineering, ASPECT, 1994
- International Workshop on Offshore Pipeline Safety, MMS, 1991
- Pipeline Crossing, ASCE, 1996
- Deepwater Pipeline Technology Conference and Exhibition, Clarion, 1997-1999

In addition, the following Journals were sourced.

- International Journal of Pressure Vessels and Piping, ASME
- Oil And Gas Journal, OGJ
- Civil Engineering, ASCE
- Welding Journal, AWS
- World Oil, Gulf

Several technical reports from government and private industry including MMS, BP Amoco, ExxonMobil and API were also reviewed.

To illustrate how the reference database has been used to identify information on available data, Tables 2.1 to 2.6 provide extracts of information obtained from those references which contain data for different defect damage types. It can be observed that a significant number of references contain defect data, particularly for corrosion defects.

Ref No.	Author	Main Topic.	General Description
267	Chouchaoui and Pick	Interaction of Corrosion Pits	Describes results of experimental and finite element studies on burst strength of pipes with multiple corrosion pits.
268	Chouchaoui and Pick	Corrosion assessment procedures	Proposes a comprehensive 3 level corrosion procedure drawn from series of burst tests on pipe sections with both service and simulated corrosion and a complementary series of FE analyses.
222	Roberts and Picks	Longitudinal stress assessment of corroded line pipe	Most techniques consider only the circumferential stress in the pipe in predicting the burst pressure of corroded pipe. Tests on experimental pipe sections and FE analyses to investigate longitudinal stress are assessed.
223	Wang, Smith, Popelar and Maple	Assessment procedure for corrosion under combined loading	Full scale tests of 48 inch diameter corroded pipe with FE data under combination of bending and other secondary loads.
140	Smith and Grigory	Assessment procedure of corrosion under combined loading	Full scale, small scale and FE studies on corroded pipes subjected to combined loading.
141	Cronin, Roberts and Pick	Assessment procedure for long corrosion grooves in pipes	Measured burst pipe tests with various corrosion geometries compared with FE analyses for long corrosion grooves.
284	Bubenik	Corrosion under combing loading	Combination of linear and non-linear FE studies supported by experiments under internal pressure and axial loading.
278	Stewart, Klever and Ritchie	Burst strength intact and corroded pipes	Validation of model against limited set of burst tests on uncorroded and corroded pipes.
273	Kanninen, Grigory et al.	Corrosion assessment procedure under combined loading	Validation of FE data against existing experimental data.
308	Hopkins and Jones	General corrosion assessments	Extensive full scale burst test experimental study into the behavior of long and complex shaped corrosion and interacting corrosion. Results compared with other data.

Table 2.1: Summary of Relevant References for Data on Corrosion (continued…)

Ref No.	Author	Main Topic	General Description
330	Wang	Corrosion method (combined loading)	Finite element analyses conducted for combined loading compared to existing database of 86 burst tests on corroded pipes.
320	Kiefner and Vieth	Remaining strength of corroded pipe lines	Experimental database of burst tests on corroded pipe.
317	Jones et al.	General corrosion assessment	Results of experimental and finite element study under internal pressure with corrosion occurring at bottom of pipe.
280	Andrews	Effect of corrosion on fracture/fatigue resistance	Results in heat affected zone of girth weld seam examined using FE and experimental data.
74	Rosenfeld et al.	Corrosion assessment procedure	A proposed corrosion procedure is compared with full scale burst tests of 168 pipes containing actual or simulated metal loss corrosion of various configurations.

Table 2.1: Summary of Relevant References for Data on Corrosion (...continued)

Ref No.	Author	Main Topic	General Description
192	Stevick, Haart and Flanders	Fatigue assessment of dented pipelines	Fatigue assessments of damages pipeline. Data compared with S-N predictions.
194	Hagiwarara et al.	Fatigue assessment of severely gouged line pipes	Fatigue tests on ERW line pipes with severe denting/gouge carried out.
195	Rosenfeld and Kiefner	Fatigue behavior of dented pipes	Dent fatigue tests compared with analytical model. Influence of dent geometry, pipe strength and pipeline operation on fatigue life estimated.
269	Fowler et al.	Fatigue of dented pipe	Describes an S-N based procedure for fatigue assessment of plain dents including stress concentration factors, based on FE and experimental validation.
307, 309, 311	Hopkins et al.	Fatigue/burst pressure of dented pipes	Experimental research on plain dents, combined dents carried out to provide guidelines for treatment of dents and combination of dents and defects.
55	Rosenfeld et al.	Fatigue of shallow dents in girth welds	Predicted fatigue lives compared with 5 experimental pipe tests with dents in girth welds.
50	Fowler et al.	Fatigue of pipes with dents/gouges	Further assessment of experimental data/FE data (i.e. above reference 269.)

Table 2.2: Summary of Relevant References for Data on Mechanical Damage Defects

Ref No.	Author	Main Topic	General Description
275	Leggatt and Challenger	Weld defect assessment procedure	Validation of PD 6493 approach for assessment of girth weld defects against Canadian database of full scale pipe bend tests.
351	Roodbergen and Denys	Fracture methodology for assessing girth weld defects	Application of various methodologies (i.e. codes) to a variety of girth weld defects for different pipe diameter/wall thickness combinations and line pipe grades.
286	Coote et al.	Avoidance of brittle failure	Full scale tests on girth welds and pipes containing failure circumferential defects compared with Canadian code and PD 6493.
298, 299	Glover et al.	Fracture methodology	Extension of work undertaken by Coote et al.
283	Broekhoven and Rongen	Verification of fracture analysis	Structures of various degree of complexity were tested including forty-three full scale pipeline sections tested with internal pressure and wide plate tests. Failure data compared to various codes.
52	Pistone et al.	Assessment of girth weld defects in ductile/brittle transition zone	Full scale bend and wide plate tension tests on X65 pipe material compared with PD 6493 predictions
82	Balsara	Application of advance fracture mechanics	Results from a series of seven pipe ring tests using sections from 36” diameter, 15.9 mm nominal wall thickness, API 5 LX material with different notches, compared with PD 6493 and R6 procedures.

Table 2.3: Summary of Relevant References for Data on Girth Weld Defects

Ref No.	Author	Main Topic	General Description
46	Buitrago et al.	S-N data on critical girth weld components	Fatigue data on critical welds, development of S-N curves and methodology for assessment.
319	Jutla et al.	Review of S-N curves and data for pipelines	Derivation of S-N design curves from limited data.
326, 328, 329	Vosikovsky	Fatigue crack growth data	Fatigue crack growth data on several API pipeline steels for various environmental test conditions.
327	Vosikovsky et al.	Fatigue crack growth data	Fatigue crack growth data on API 5L X65 pipeline steel in crude oil saturated with H_2S.
297	EBARA ET AL.	Fatigue crack growth data	Derivation of crack growth rates for HT50 TMCP steel in sour crude oil and comparison with other data.
44	Robinson et al.	Fatigue crack growth data	Derivation of crack growth and thresholds for high strength steel up to 700 MPa in sulphate reducing bacteria environment.

Table 2.4: Summary of Relevant References for S-N (Fatigue) and Crack Growth Data

Ref No.	Author	Main Topic	General Description
208	Willmot M. et al.	Growth of SCC under fluctuating load	Experiments to determine crack growth rates under different corrosion environments for pipe line steels.
212	Zheng W et al.	Growth of SCC under hydro-testing	Experiments on X52 pipeline steel with different coating conditions, crack lengths and depths.
151	Krishnamurthy et al.	Methodology procedure to manage SCC on X52 pipeline	Experiment on in-service X52 pipeline steel and methodology (fracture model) developed.
157	Plumtree	SCC, crack growth monitoring under field conditions	Experiments on API X60 grade pipeline steel placed in service in 1972 and removed in 1988. Measurements of crack growth rates and model to assist inspection monitoring.
150	Zheng	SCC crack growth subject to fluctuating pressure	Experiments on range of pipeline steels (X52, X60, X65 and X70) under different pressure fluctuations with range of different cracks.

Table 2.5: Summary of Relevant References for Stress Corrosion Cracking Data

Ref No.	Author	Main Topic	General Description
53	Irisarri et al.	Fracture behavior of high strength pipeline steel	CTOD and Charpy impact tests on API 5L grade X70 pipeline steel.
237	Kostic et al.	Material aspects of X-80 pipeline steel	Metallurgical examination, fracture toughness of X-80 steel compared with other grades.
242	Mak and Tyson	Material assessment of pipeline steel	Eight pipes in service over a period of 30 years have been tested to evaluate toughness properties. Range of steel grades X52 – X70.
298, 299	Glover et al.	Pipeline using high strength steels	Toughness data on MMA girth welds for a 914 mm 11.1mm thick grade 50X pipeline steel evaluated.
310	Hopkins et al.	Toughness data for different welding processes	Extensive program of CTOD tests from two pipelines.
288	Slater and Davey (OTH 86233)	Statistical assessment of weld fracture toughness data	Comprehensive analysis of pipeline girth weld data based on information gathered from nine offshore operators and other sources.
364	McKeehan et al.	High yield to tensile ratio assessment	Evaluation of higher strength steel pipeline material (ref. yield to tensile ratio)

Table 2.6: Summary of Relevant References for Data on CTOD/Fracture Toughness

2.2 Interviews with Operators

A number of interviews were held with major operators having pipelines in UK, Norwegian and/or US waters. The main objectives of the interviews were to identify the current approach of industry to pipeline inspection and defect assessment and the perceived trends in future technology development. Detailed notes of meetings are provided in Appendix A. A summary of the main points is given below.

- European interviewees reported very few problems had been experienced with their pipelines. This was thought to reflect benign sweet gas conditions.

- In Gulf of Mexico waters, corrosion defects were reported as being most prolific, however, loss of inventory was more commonly due to third party interference (e.g. anchor drag).

- In-service anomalies found during inspections were mostly related to internal corrosion.

- It would appear that the imposition of high standards of inspection during pipeline manufacture is cost effective. One operator has gone even further in stipulating stricter (than code) requirements on steel chemistry (to improve weldability) and dimensions (to facilitate fabrication).

- Operators, especially those in Europe, would like to dispense with the need to conduct hydro testing of new pipelines. This is seen as expensive, time-consuming and of doubtful benefit, particularly when the longitudinal seam welds, which experience most of the stress imposed in such tests, have already been pressure tested at steel mills during pipe manufacture.

- European operators sometimes use smart pigs for inspection. They were, however, regarded as an expensive option carrying attendant risks (i.e. stuck pigs). They are increasingly only being used when there are other indications of degradation in pipeline integrity.

- The recommendations of ASME B31G are commonly used for defect assessment in the US. These were generally believed to be conservative.

- Smart pig inspections are not routinely used in the Gulf of Mexico. The majority of existing lines were not originally designed or built to accommodate smart tool pigs.

- Issues affecting smart pigging often center around the prevention of the tool becoming stuck in a pipeline and many critical factors must be considered such as tee fittings for branching pipelines, changing line wall thickness, different line sizes, riser size and configuration, existence of pig traps, size of pig traps, and topsides facilities piping etc. The consequential loss of production, potentially from multiple facilities, and cost to locate and retrieve a stuck tool from a sub sea line in such an event, is a significant commercial risk.

- In the US, various monitoring techniques are used to mitigate environmental and commercial risks associated with potential leaks. These may include monitoring pressure drop and/or quantity balances or automated tracking of trends and alarm signals to alert for discrepancies. Helicopter fly-over is used to inspect integrity along pipeline routes or to assist in location of suspected leaks. It was felt that the level to which such monitoring was deployed within the industry varied widely and even within companies may vary between divisions according to the type of system, determined risk of failure and operating philosophy.

- Construction activity was felt to present a significant risk of damage to existing and new pipelines.

- External corrosion is not, generally, believed to be a problem for pipelines in the Gulf of Mexico. The sacrificial anode system has been shown to provide successful lifetime protection against external corrosion.

- In the Gulf of Mexico, defects associated with the development of long spans were not considered significant. In a few instances seabed scour local to the pipeline riser had resulted in increased spans.

3. OVERVIEW OF CODES/PRACTICES

3.1 General

The development of pipeline standards started in the US in the 1930's with the issue of the first B31 Code. Pipelines at that time were exclusively onshore pipelines. Later updating has resulted in a separation into a number of codes, in particular B31.4 for transportation of hydrocarbon liquids and B31.8 for transportation of natural gas. Amendments to cover offshore pipelines have been developed and issued. The ASME B31.4 and B31.8 codes, together with API 5L and API 1104 specifications for line pipe and pipeline welding, respectively, have been used and referenced by the petroleum and natural gas industries worldwide.

However, the development of significant hydrocarbon reserves in Europe and other parts of the world since the sixties has lead to diversity of pipeline standards and specifications on a national and a company level. Many industrialized countries developed their own pipeline standards reflecting the prevailing requirements and interests of their own experts and regulatory authorities. Thus significant differences in safety and technical requirements for pipelines developed between the various national codes. On a company level a similar process took place. This resulted in an increasing volume of standards and specifications with differences in their requirements not always relevant to the final product.

In recognition of this, the Technical Committee 67 of ISO (ISO/TC 67) was set up with the objective to develop truly international standards for the petroleum and natural gas industries. In parallel to the ISO work, Norway decided to establish the NORSOK organization with the objective to establish common industry standards. Similar initiatives have been seen in other countries.

One operator that is strongly supporting the ISO work is STATOIL, because of its position as operator of the largest gas transmission system in the world. Statoil has seen the consequences of different pipeline standards between neighboring countries (Gas transport pipelines like Zeepipe 1, Europipe I and NorFRa cross different national sectors along their routes from the North Sea to continental Europe). National pipeline regulations and industry standards apply within the sectors resulting in, for example, varying wall thickness for the same pipeline from one sector to the next.

Pipeline technology has improved over the years resulting in improved fabrication tolerances, and better welding and NDT techniques. Furthermore, improved knowledge of pressure behavior, external loads, corrosion protection and operational aspects has also taken place. These improvements have contributed to a need to update existing codes and standards.

Offshore pipeline systems can be grouped into two categories based upon their usage, oil pipeline systems and gas pipeline systems. The design, installation, inspection, repair and maintenance of offshore pipelines are covered by a number of national codes and standards, which include the following:

- Pipeline Transportation System for Liquid Hydrocarbons and other Liquids, ASME B31.4, 1998, US
- Gas Transmission and Distribution Piping Systems, ASME B31.8, 1995, US
- Code of Practice for Pipelines, BSI 8010, Part3, 1993, UK
- Oil and Gas Pipeline systems, CAS-Z662-99, 1999, Canada
- Rules for Submarine Pipeline Systems, DNV 1996, 1996, Norway
- Rules for Subsea Pipelines and Risers, GL 1995, Germany
- Pipeline Transportation System for the Petroleum and Natural Gas Industries, ISO 13623, 1995
- Design of Long Distance Transmission Pipelines, SniP2.05.06-85, 1985, Russian

These codes and standards specify minimum requirements for the design, fabrication, installation, operation, re-qualification and abandonment of offshore pipeline systems. They serve as guidelines for designers, clients, contractors and others not directly involved in the certification process. These codes and standards are not design handbooks, and the exercise of competent engineering judgment is a necessary requirement to be employed concurrently with their use.

To design an offshore pipeline system, hydraulic, mechanical and structural design manuals, even textbooks, are required besides the above-mentioned codes and standards. The design process of offshore pipeline system is typified in Figure 3.1. The required design checks are typically as shown in Figure 3.2.

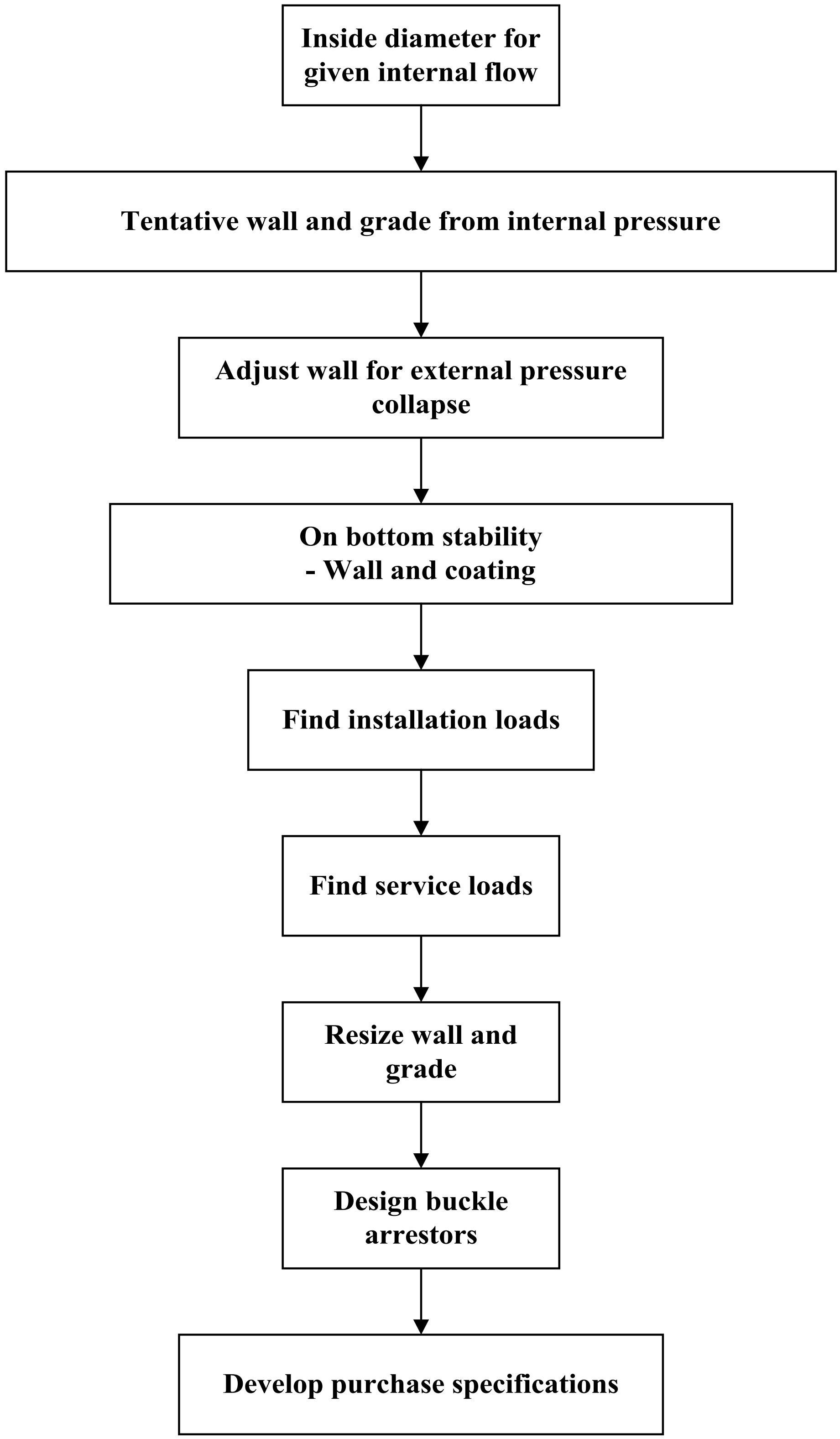

Figure 3.1: Offshore pipelines design flow chart

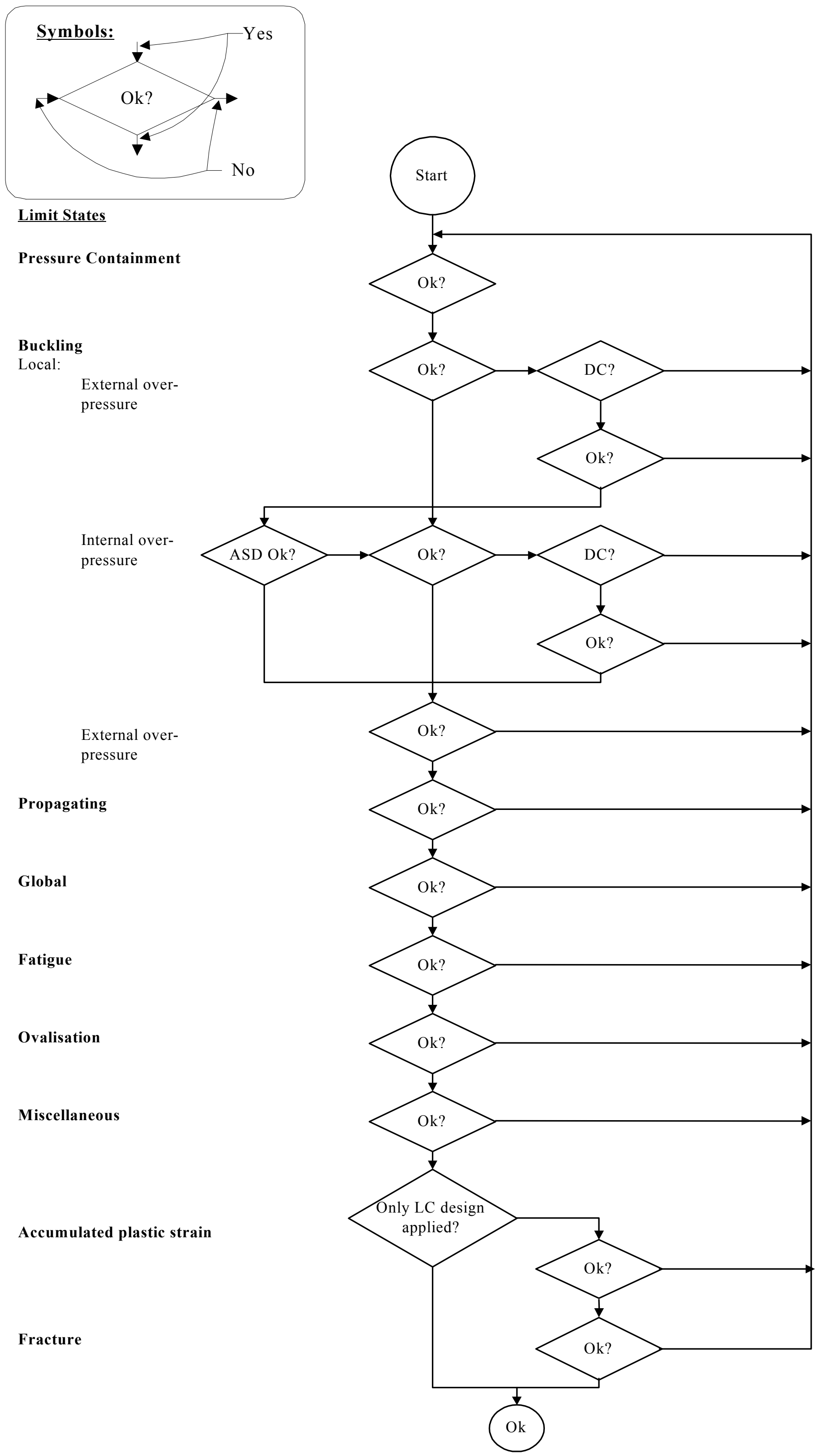

Figure 3.2: Typical flow diagram for design checks

3.2 Probabilistic Design Methods

A pipeline shall fulfill two basic functional requirements: the individual probabilities of excessive deformations, resulting in an unserviceable line, and burst, resulting in loss of contents, must be sufficiently low. The probabilities of excessive deformations and burst can be assessed using reliability analysis. There are generally three levels in such analysis at which structural safety may be treated.

Level 1: A semi-probabilistic design process in which the probabilistic aspects are treated specifically in defining partial safety factors to be applied to characteristic values of loads and structural resistances. A level 1 structural design is what is now commonly called a limit state design. It is used as a practical method of incorporating reliability methods in the normal design process.

Level 2: A probabilistic design process with some approximation. In this process, the loads and the strengths of materials and section are represented by their known or postulated distributions (defined in terms of relative parameters such as type, mean, and standard deviation) and some reliability level is accepted. Level 2 methods are not necessary for component designs (handled by level 1 limit state design) but are valuable for economic planning, monitoring, maintenance decision-making and structural integrity evaluation.

Level 3: A design process based upon full probabilistic analysis for the entire structural system. Level 3 methods, which take into account joint probabilistic distributions of load and strength parameters and uncertainties in the analysis, are extremely complex and limited in practicality. They are used in special circumstances where the environment is particularly sensitive or where cost savings justify the additional expense of complex analyses.

Situations where probabilistic methods might be used include the determination of the factored resistance of new systems and materials and the levels of safety to control new hazards.

3.3 Reliability-Based Calibration

Any design code provides a certain safety margin against failure in design. This inherent safety margin is mainly related to the choice of safety factors sometimes selected on a more or less arbitrary basis. This has led to different safety levels for different design checks occurring within codes.

Limit state design implies that the performance of the pipeline is described in terms of a set of limit states for which adequate safety margins are quantified. For the entire limit states, a set of safety factors are calibrated for each safety class using a structural reliability approach. It introduces flexibility in specific conditions and provides design with a consistent safety level without compromising the safety objective. However, in a sound calibration process a varying degree of conservatism needs to be introduced for individual design scenarios depending on the knowledge of the prevailing loads, pipe capacities, etc. Thus, the calibrated design criteria being generally applicable may be expected to be conservative on average.

3.4 Design Criteria and Methods in Codes

3.4.1 ASME B31.4 1998 and B31.8 1995

ASME B31.4 and ASME B31.8, together with the API 5L and API 1104 specifications for line pipe and pipeline welding, respectively, are the most widely applied pipeline codes for the Petroleum and Natural Gas Industries.

The Codes are based on traditional allowable stress design methods. The design factor for general route pipelines is 0.72 for liquid pipelines based on nominal wall thickness. In setting the design factor, due consideration has been given to and allowance has been made for the under-thickness tolerance and maximum allowable depth of imperfections provided for in the specification approved by the code.

For the gas transmission and distribution piping systems, the code specifies a Location Class as follows:

- Location Class 1 is any l mile section that has 10 or fewer buildings intended for human occupancy. Location Class 1 is intended to reflect areas such as wasteland, desert, mountains, grazing land, farmland, and sparsely populated areas.

- Location Class 2 is any 1-mile section that has more than 10 but fewer than 46 buildings intended for human occupancy. Location Class 2 is intended to reflect areas where the degree of population is intermediate between location Class 1 and Location Class 3 such as fringe areas around cities and towns, industrial areas, ranch or country estates.

- Location Class 3 is any 1-mile section that has 46 or more buildings intended for human occupancy except when a location Class 4 prevails. Location Class 3 is intended to reflect areas such as suburban housing developments, shopping centers, residential areas, industrial areas.

- Location Class 4 includes areas where multi-story buildings are prevalent, and where traffic is heavy or dense and where there may be numerous other utilities underground. Multi-story means 4 or more floors above ground, including the first or ground floors.

Allowable tensile and compressive stress values for materials used in structural supports and restraints shall not exceed 66% of the specified minimum yield strength. Allowable stress values in shear and bearing shall not exceed 45% and 90% of the specified minimum yield strength, respectively.

3.4.2 API RP 1111

Limit State Design criteria for *offshore hydrocarbon pipelines* are presented in API Recommended Practice RP 1111. Limit State Design is adopted in this RP to provide a uniform factor of safety with respect to rupture or burst failure as the primary design condition independent of the pipe diameter, wall thickness, and grade.

The criteria cover the design, construction, testing, operation, and maintenance of offshore steel pipelines utilized offshore in the production support, or transportation of hydrocarbons. However, the document incorporates by reference all or parts of several existing codes, standards, and RPs that have been found acceptable for application to offshore hydrocarbon pipelines such as ASME B31.4 or ASME B31.8, which have been addressed in Section 3.4.1.

3.4.3 BS 8010

The code takes the allowable stress design method as the basic design method. The design factors, appropriate to the assessment of allowable stress, are given below in Table 3.1.

Hoop stress		**Equivalent stress resulting from functional and environmental or accidental loads**		**Equivalent stress arising from construction or hydro test loads**	
Riser	**Seabed**	**Riser**	**Seabed**	**Riser**	**Seabed**
0.6	0.72	0.72	0.96	1.0	1.0

Table 3.1: Design factors f_d

Alternatively, the code allows that the acceptability of construction loads may be assessed on an allowable strain basis. The limit on equivalent stress may be replaced by a limit on allowable strain, provided that all the following conditions are met:

- Under the maximum operating temperature and pressure, the plastic component of the equivalent strain does not exceed 0.001. The reference state for zero strain is the as-built state.

- Any plastic deformation occurs only when the pipeline is first raised to its maximum operating pressure and temperature, but not during subsequent cycles of depressurization, or reduction in temperature to the minimum operating temperature.

- The D/t ratio does not exceed 60.

- Welds have adequate ductility to accept plastic deformation.
- Plastic deformation reduces pipeline flexural rigidity; this effect may reduce resistance to upheaval buckling and should be checked if upheaval buckling might occur.

This approach is only permissible where geometric considerations limit the maximum strain to which the pipeline can be subjected and where the controlled strain is not of a cyclic or repeated nature.

3.4.4 DNV 1996

The DNV Rules for Submarine Pipeline Systems were first issued in 1976 and have since been updated in 1981 and most recently in 1996. It has as one of the basic objectives to "Provide an internationally acceptable standard of safety with respect to strength and performance by defining minimum requirements for the design, material selection, fabrication, installation, commissioning, operation, maintenance, re-qualification and abandonment of submarine pipeline systems".

In DNV '96 limit state design principles are adopted but it allows, as an alternative, probabilistic design provided competent personnel apply an acceptable reliability method. The design format of the DNV '96 Rules is called a Load and Resistance Factor Design (LRFD) except for the requirement for pressure containment, which is given in the traditional Allowable Stress Design (ASD) format.

The principle of the LRFD design format is to ensure that the level of structural safety is such that the design load on the pipeline does not exceed the design resistance of the pipeline except for a stated level of failure probability.

The acceptable target failure probabilities should be in compliance with the implied safety in the rules. By performing a reliability analysis for a specific design case or for a more restrictive scope of scenarios the inherent conservatism may be reduced.

In DNV '96, a novel safety class concept is introduced. Based on the fluid category, location class and phase, the pipeline is classified into a safety class. See Tables 3.2 to 3.4.

Category	Description
A.	Typical non-flammable water-based fluids.
B.	Flammable and/or toxic substances that are liquids at ambient temperature and atmospheric pressure conditions. Typical examples would be oil, petroleum products, toxic liquids and other liquids that could have an adverse effect on the environment if released.
C.	Non-flammable substances that are gases at ambient temperature and atmospheric pressure conditions. Typical examples would be nitrogen, carbon dioxide, argon and air.
D.	Non-toxic, single-phase gas which is mainly methane.
E.	Flammable and toxic substances that are gases at ambient temperature and atmospheric pressure conditions and which are conveyed as gases or liquids. Typical examples would be hydrogen, methane (not otherwise covered under category D), ethane, ethylene, propane, butane, liquefied petroleum gas, natural gas liquids, ammonia, and chlorine.

Table 3.2: Categorization of Fluids

Location Class	Description
1	The zone where no frequent human activity is anticipated along the Pipeline route
2	The part of the Pipeline/Riser in the near platform (manned) zone or in areas with frequent human activity. The extent of zone 2 should be based on appropriate risk analyses. If no such analyses are performed a minimum distance of 500 m could be adopted.

Table 3.3: Definitions of Location Classes

Phase	Fluid Category A and C		Fluid Category B, D and E	
	Location Class		Location Class	
	1	2	1	2
Temporary	Low	Low	Low	Low
Operational	Low	Low	Normal	High

Table 3.4: Normal Classification of Safety Classes

Determination of appropriate target safety levels is fundamental to the process of developing new design criteria through the application of reliability methods. A target safety level is defined as the maximum acceptable failure probability level for a particular limit state design to be accepted, see Table 3.5 below:

Limit State Category	Probability Bases	Safety Classes		
		Low	Normal	High
SERVICEABILITY	Annual per Pipeline(1)	10^{-2}	10^{-3}	10^{-3}
Ultimate	Annual per Pipeline(1)	10^{-3}	10^{-4}	10^{-5}
Fatigue	Lifetime probability per Pipeline(2)	10^{-3}	10^{-4}	10^{-5}
Accidental	Annual per km(3)	10^{-4}	10^{-5}	10^{-6}

Notes:
(1) Or the length of the period in the temporary phase
(2) No inspection and repair is assumed, temporary and in-service conditions considered together
(3) Refers to the overall allowable probability of severe consequences.

Table 3.5: Recommended Target Safety Levels

The evaluation of the target safety level for pipelines should primarily be based on the implied safety in currently accepted design practice, using uncertainty measures representative at the time when the code was made. Further, the nature of failure and the actual consequence potential in terms of hazard to human health and safety, damage to the environment, economic losses, and the amount of expense and effort required to reduce such hazard potential should be take into account.

With no implicit safety level available, the rules provide recommendations on target failure probabilities versus safety class and limit state category. The basis for the values of safety factor rely on a conservative assessment of implied safety in current accepted design practice guided by accident statistics and engineering judgment.

Limit State Categories:

Typical Limit States and corresponding limit state categories for a pipeline may be:

Serviceability/Limit State (SLS) Category

- Ovality / ratcheting Limit State
- Accumulated plastic strain Limit State
- Damage due to or loss of weight coating

- Yielding

Ultimate Limit Sate (ULS) Category

- Bursting Limit State
- Local buckling Limit State (pipe wall Limit State)
- Global buckling Limit State (normally for load-controlled condition)
- Unstable fracture and plastic collapse Limit State

Fatigue Limit State (FLS)

- Fatigue due to cyclic loading

Accidental Limit State (ALS) Category

- Dropped objects
- Trawl gear hooking
- Earthquake.

The hoop stress formula in the DNV rules is the same as in the ISO standard. The design factor requirements for pressure containment is, however, formulated as a dual requirement, namely as a check against yielding and a check against bursting as shown in Table 3.6

Safety Class	Low	Normal	High
Yielding	0.83	0.77	0.77
Bursting	0.72	0.67	0.64

Table 3.6: DNV '96 Hoop Stress Design Factors

A further possibility to benefit the designer is in the application of high quality material. The design factors given in Table 3.7 below apply when specified material quality requirements are satisfied.

Safety Class	Low	Normal	High
Yielding	0.85	0.80	0.80
Bursting	0.74	0.70	0.67

Table 3.7: DNV '96 Hoop Stress Design Factors, best material

Differences can be noted when comparing DNV with ISO as follows:

- The design requirements of ISO are based on yielding exclusively, whilst DNV '96 applies both yielding and bursting as actual failure modes and presents requirements for both.
- The design factors specified by DNV '96 for yielding are generally the same as the ones specified by ISO. Whilst the factors in ISO basically rest on ASME B31.4/B31.8 and long-term industry practice, extensive research programs support the design factors in DNV.
- The design factors in ISO are specified depending on fluid category and location, whilst those of DNV '96 are given by safety Class and in spite of the fact that the two standards generally specify the same design factors for the yielding criterion, the two design formats are basically different and may give different results in some cases.

3.4.5 CSA Z662-1999

In the code CSA Z662-99, allowable stress design is the basis for the design criteria. The stress design requirements are considered to be adequate under conditions usually encountered and for general stress design of conventional pipeline systems. The design factors are given in Table 3.8

System	Load condition		
	A	B	Pressure Testing
Pipelines	0.72	1.00	1.00
Risers	0.60	0.80	1.00

Table 3.8: CSA Z662-99 Design Factors

As an alternative, the code permits oil and gas pipelines to be designed in accordance with the requirements of limit state design methods given in Appendix C of the code as illustrated in Figure 3.3, provided that the designer is satisfied that such designs are suitable for the conditions to which the pipelines are to be subjected.

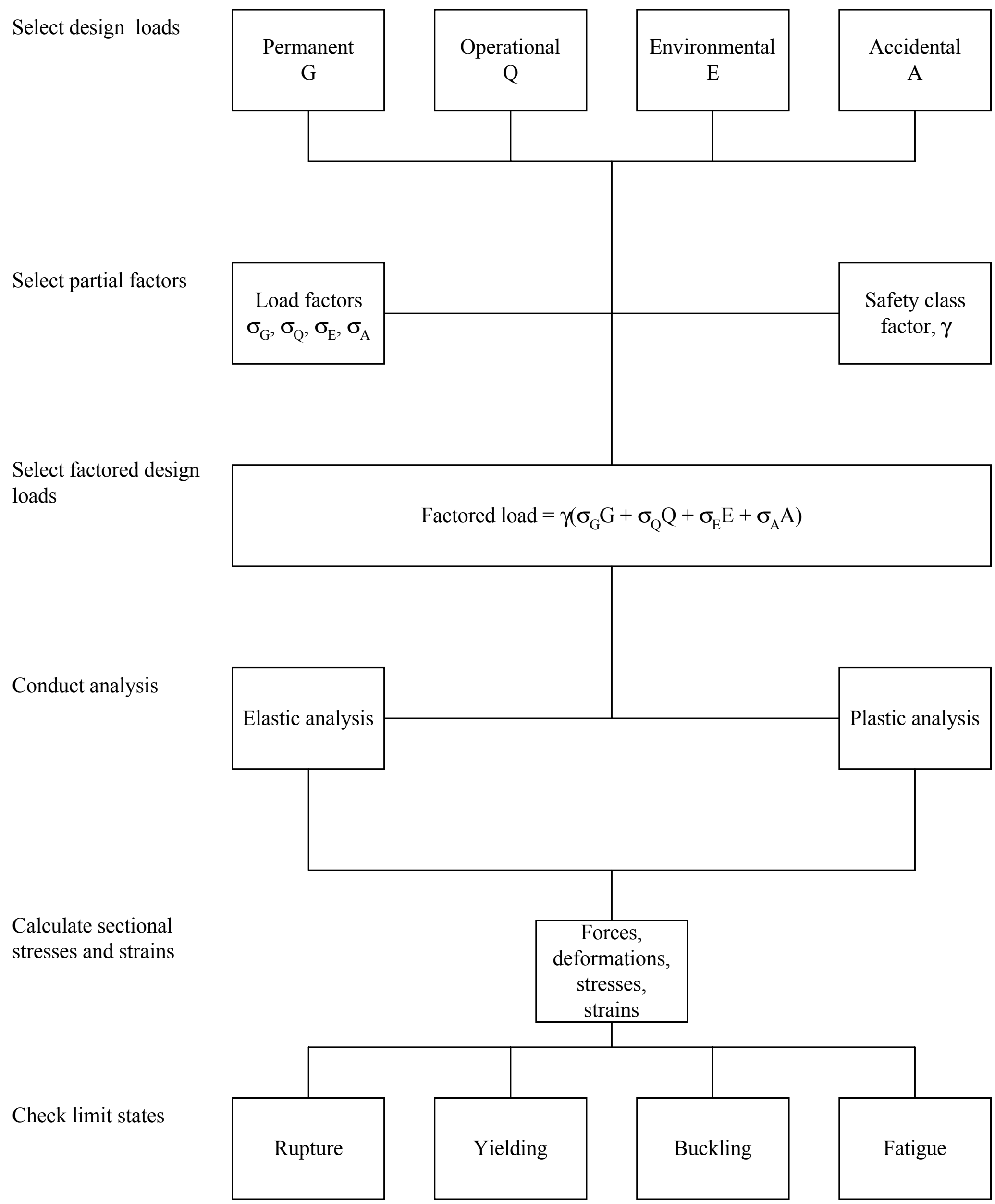

Figure 3.3: Limit state design methodology (CSA Z662-99)

3.4.6 ISO/DIS 13623-1996

The standard uses maximum permissible stresses as the basic concept for ensuring pipeline integrity and serviceability. Formulas and design factors are given for hoop stress and equivalent stress. Strain based design is allowed in specific cases.

The use of the reliability based limit state design method may be applied with one important exception, namely that of design for pressure containment for the general route part of the pipeline.

The hoop stress formula of the ISO standard is based on the average between the inner and outer diameters of the pipeline and on the minimum wall thickness. This is different from the traditional formulation (i.e. ASME), which is based on nominal outer-diameter and nominal wall thickness. The traditional formulation was established for thin wall pipelines, whilst modern offshore gas trunk lines are designed to much higher pressures giving thicker walls.

It may also be noted that European standards vary between the countries. Statoil for example has used a formulation based on inner diameter and minimum wall thickness. The result of the different formulations is that different standards in reality express different levels of steel utilization for pressure containment in spite of the fact that they all prescribe the same design (i.e. utilization factor of 72% of yield strength).

Another effect inherent in the traditional design formulation for pressure containment is that the real steel strength utilization expressed by the formulation is different when applied to pipelines with highly different design pressures. Thus the requirement works differently for an onshore gas pipeline with a design pressure typically in the range 60-80 bar and a flow line with a design pressure of say 400 bar both fabricated with the same wall thickness tolerances (e.g. API 8%).

The practical consequences are such that the requirement for pressure containment normally determines the wall thickness of the pipeline steel. Therefore for the above example this would mean that the flow line would need relatively more steel than an onshore gas line in order to meet the same requirements when using the traditional formulation.

The hoop stress factors were calibrated to lead to the same wall thickness as required in ASME B31.4 and B31.8 for an average pipeline with a D/T of 60 and a 8% wall thickness tolerance. These factors are given in Table 3.9 below.

Location	Design factor u
General Route (1)	0.77
SHIPPING LANES, DESIGNATED ANCHORING AREAS AND HARBOUR ENTRANCES	0.77
Landfalls	0.67
Pig traps and multipipe slug catchers	0.67
Risers and station piping	0.67

Note:
(1) The factor may be increased to 0.83 for pipelines conveying category C and D fluids.

Table 3.9: ISO Hoop stress design factors for offshore pipelines

4. PIPELINE INSPECTION TECHNIQUES

4.1 Introduction

As the international pipeline system ages it is of ever increasing importance that operators are supplied with the technology to inspect and assess the state of their pipelines. It is for this reason that inspection tools have been developed and introduced into the market utilizing non-destructive testing techniques (NDT) to inspect pipelines without the need of a shut down during the survey. These vehicles are generally known as on-line inspection tools or intelligent or 'smart' pigs. Furthermore with the introduction of large diameter, high-pressure offshore lines for oil or gas in the last twenty years and constant addition to this offshore network on a worldwide scale, smart pigs are increasingly being used in the commissioning stage in order to perform base-line surveys.

Information on inspection techniques and pigging can be found in codes and standards and in the open literature. These were examined and the findings are reported in this Section 4. Summaries of the content of individual papers on inspection techniques are given in Appendix B.

For purposes of inspection, it is useful to distinguish flaws and defects in pipelines into one of the following categories: geometric anomalies; metal loss; cracks or crack-like defects.

Geometric anomalies are generally caused by mechanical damage and are characterized by a change in the geometry of the pipe. They include dents, ovalities, wrinkles etc. Two reasons why these may be important are a critical reduction in free internal diameter and the formation of locally acting stress concentrations. Regular or smart pigs can be used for their detection with limited degrees of accuracy in location and sizing.

Metal loss features usually relate to internal or external corrosion although sometimes, mechanical damage is involved (gouging). Smart corrosion-detection pigs must therefore be able to reliably detect and measure corrosion flaws and to accurately locate them.

Cracks found in pipelines include fatigue cracks and stress corrosion cracks. Crack-like defects often include girth weld defects, described more fully in Section 1.

Table 4.1 provides a summary of the availability and applicability of pipeline integrity monitoring methods for the various defect types including, corrosion, mechanical damage, girth weld defects, fatigue cracks and stress corrosion cracking.

Table 1.0
Summary of Pipeline Integrity Monitoring Methods (Availability and Applicability) vs Observed Major Defect Types

Inspection Method	Applicability [7] of Inpsection Methods to Defect Types: corrosion [6]	mechanical damage	girth weld defect	S-N (fatigue) and crack growth	SCC
Preventive / Predictive:					
scheduled / periodic methods:					
MFL pig [1]	applicable	applicable	applicable?	applicable, surface cracks only	applicable, surface cracks only
UT pig [2]	applicable	applicable	applicable?	applicable	applicable
caliper pig (2D)	-	applicable	-	-	-
inertial mapping pig (3 D)	-	applicable	-	-	-
corrosion coupons [3]	applicable	-	-	-	-
chemical analyses [4]	applicable	-	-	-	-
cut-out and inspect	applicable	applicable	applicable	applicable	applicable
accoustic emmission	-	applicable, for plastic deformation and active crack-type defects	applicable, for active crack-type defects	applicable	applicable
hydrotest	(see note 9.)	(see note 9.)	(see note 9.)	(see note 9.)	(see note 9.)
continuous, non-intrusive [5] methods:					
thin-layer activation (TLA)	applicable	-	-	-	-
neutron activation (NA)	applicable	-	-	-	-
field signature (FS)	applicable	-	-	-	-
fixed ultrasonic (UT)	applicable	-	-	-	-
strain gauge, external [10]	-	applicable	-	-	-
continuous, intrusive [5] methods:					
electric resistance probe	applicable	-	-	-	-
electrochemical probe	applicable	-	-	-	-
Contingent:					
scheduled / periodic methods:					
visual surveillance, various	only applicable upon failure	only applicable upon failure	only applicable upon failure	only applicable upon failure	only applicable upon failure
fixed point leak detection, non-RTC [8]	only applicable upon failure	only applicable upon failure	only applicable upon failure	only applicable upon failure	only applicable upon failure
leak detection, accoustic emission pig	only applicable upon failure	only applicable upon failure	only applicable upon failure	only applicable upon failure	only applicable upon failure
continuous, methods:					
leak detection, RTC	only applicable upon failure	only applicable upon failure	only applicable upon failure	only applicable upon failure	only applicable upon failure

notes:
1. Equally applicable in "wet" or "dry" service pipelines.
2. Applicable in "wet" service pipelines. The technology requires a liquid medium in which to function.
3. Used to measure weight loss corrosion. Use and effectiveness is limited by access to inlet, outlet, and corrosion susceptable sections of the pipeline.
4. Eg.; iron content analysis of water samples, pig trap returns, inhibitor residuals drawn from the pipeline.
5. Intrusive is used in the sense that the methods intrude physically into the pipeline with consequent maintenance requirements and interference with pigging operations.
6. Applicability and effectiveness varies with corrosion mechanism. Examples include the following:
   6.1 The TLA, NA, fixed UT and FS methods are all effective in monitoring "general" corrosion
   6.2 The FS method is also effective in monitoring "pitting" corrosion
7. Though applicable, technologies vary in detection / measurement accuracy a complete comparision of which is beyond the scope of this simple table. Example resolution accuracies follow:
   7.1 The TLA and NA methods have a resolution of 1 % of the activated thickness
   7.2 The fixed UT method has a resolution of 100 micrometers
   7.3 The fixed FS method has a resolution of 0.1% of the wall thickness
   Not all technologies have been adapted for, or have operational experience with, subsea pipelines.
8. Real Time Computational (RTC).
9. Hydrotesting is a non-defect specific "pass/fail" test that can not detect defects if they do not lead to leaks or ruptures during the test.
10. Depending on pipeline length fiber optic strain gauge technology will be more applicable.

Table 4.1: Summary of Monitoring Methods for Typical Major Defects

4.2 Conventional Non-destructive Techniques

The following techniques are addressed in various codes as summarized below:

A. **(Manual/mechanized) Liquid Penetrant Testing (PT)**

Environmental Cracking including chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking; Fatigue cracking; Creep Cracking; Surface imperfection detection for ferromagnetic materials; Crater cracks or star crack.

Codes:

API 570: Environmental Cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking; Fatigue cracking; Creep Cracking.

DNV 96: Surface imperfection detection for ferromagnetic materials.

API 1104: Crater cracks or star cracks.

B. **(Manual/Auto) Magnetic Particle Testing (WFMT)**

Environmental Cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking, Fatigue cracking; Creep Cracking; Surface imperfection detection for ferromagnetic materials; Discontinuity (crack).

Codes:

API 570: Environmental Cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking, Fatigue cracking; Creep Cracking.

DNV 96: Surface imperfection detection for ferromagnetic materials.

API 1104: discontinuity (crack).

C. **(Auto/Manual) Ultrasonics (UT)**

Environmental Cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking; Creep Cracking; Weld corrosion; Internal imperfection detection; Preferred for planar imperfections; Weld imperfections including partial penetration butt welds, weld crown, elongated surface imperfections, elongated internal imperfections, isolated surface imperfections, isolated internal imperfections, crack burns, unequal leg length-fillet welds, accumulation of imperfections.

Codes:

API 570: Environmental Cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking, Fatigue cracking; Creep Cracking.

DNV 96: Surface imperfection detection for ferromagnetic materials.

API 1104: discontinuity (crack).

D. **(Auto/Manual)Ultrasonic Scanning**

Erosion and corrosion; Internal imperfection detection; Weld discontinuity.

Codes:

API 570: Erosion and corrosion.

DNV 96: Internal imperfection detection.

API 1104: Weld discontinuity.

E. **Radiographic Profile**

Erosion and corrosion; Weld corrosion.

Codes:

API 570: Erosion and corrosion; Weld corrosion.

F. **Radiography (Radiographer/Real time filmless)**

Corrosion beneath lining and deposits; Creep Cracking; Weld imperfection; Internal imperfection detection, preferred volume imperfection detection; Weld imperfections including inadequate penetration, incomplete fusion, internal concavity, burn through, slag inclusions, porosity, cracks, undercutting; Weld imperfections including partial penetration butt welds, weld crown, elongated surface imperfections, elongated internal imperfections, isolated surface imperfections, isolated internal imperfections, crack burns, unequal leg length-fillet welds, accumulation of imperfections.

Codes:

API 570: Corrosion beneath lining and deposits; Creep Cracking; Weld imperfection.

DNV 96: Internal imperfection detection, preferred volume imperfection detection.

API1104: Weld imperfections including inadequate penetration, incomplete fusion, internal concavity, burn through, slag inclusions, porosity, cracks, undercutting.

CSA Z662: Weld imperfections including partial penetration butt welds, weld crown, elongated surface imperfections, elongated internal imperfections, isolated surface imperfections, isolated internal imperfections, crack burns, unequal leg length-fillet welds, accumulation of imperfections.

G. **Eddy Current**

Erosion and corrosion, Surface imperfection detection for ferromagnetic materials.

Codes:

API 570: Erosion and corrosion.

DNV 96: Surface imperfection detection for ferromagnetic materials.

H. **Acoustic Emission**

Fatigue cracking; Creep Cracking; Remote leak detection.

Codes:

API 570: Fatigue cracking; Creep Cracking. Remote leak detection.

I. **In-situ Metallography**

Creep Cracking.

Codes:

API 570: Creep Cracking.

J. **Thermography**

Leak detection; Hot spots.

Codes:

API 570: Leak detection; Hot spots.

In addition to the above, further information on selected techniques can be found in the following standards and codes:

Radiography: ISO 1106-1, ISO 1106-2, ISO 1106-3, ISO 5579.

Ultrasonic: ASME boiler and Pressure Vessel Code.

Magnetic Particle: ASTM E709, ASTM E1444.

Dye Penetrant: ASTM E1417.

4.3 <u>In-Service Internal Inspection</u>

The use of in-line inspection techniques (Smart pigs) to detect and quantify the pipeline defect has gained wide acceptance in recent years.

As noted in Section 4.1 above, flaws and defects in pipelines can be distinguished into one of the following categories: geometric anomalies; metal loss; cracks or crack-like defects. While there are several different technologies available for the first two categories, cracks have proven to be the most difficult type of defect to detect, and there is currently no commercially available in-line inspection system with proven crack detection capability.

A. Geometry Pigs:

Geometry pigs are used to measure pipe internal geometry in order to detect imperfections such as ovality or dents and to ensure that a pipeline has a full round opening for its entire length. The inspection needs to determine the exact location of any point where the diameter of the pipeline is less than a predetermined dimension, and the magnitude of the reduction.

1. **Mechanical Geometry Pigs**: the most widely used mechanical tool is the Caliper Pig. As the pig travels through the pipeline, the deflection of the levers is recorded. The results can show up details such as girth weld penetration, pipe ovality, and dents.

2. **Electric Geometry Pigs**: they record, analyze and display the data from an inspection run using electronic instrumentation. As a result, the data can be manipulated and massaged to greatly expand the information from a single pipeline run.

B. Corrosion Defect Detection Pig:

1. **Semi Automatic Ultrasonic System – Mapscaner**

   To obtain quantitative results to establish the severity of metal loss or to determine the suitability of a pipe segment for continued use, RTD Mapscan, a tool which incorporates a small ultrasonic probe, can be used.

2. **Magnetic Flux Leakage Scanner – Pipescaner**

The MFL technique provides qualitative results and can give a good indication of general condition of a pipeline section. MFL is a well known mature technique, extensively used in self-contained smart pigs. A permanent magnet generates a magnetic field in the pipe wall. Internal and external volumetric defects, general corrosion or pitting, cause disturbance in the magnetic field flow, which can be detected by a Hall effect sensor.

C. **Crack Detection:**

Cracks are potentially the most dangerous types of defects in pipelines. The mechanisms of initiation and growth in particular of the so called near neutral SCC are still not fully understood and are the subject of ongoing research. SCC can occur in various forms from small isolated cracks to large crack fields containing hundreds of cracks. Since the hoop stress is usually the driving force, SCC is normally axially orientated. SCC is generally found on the external pipe surface with some preference in the longitudinal weld area but also in the base material. Its occurrence is observed to be largely associated with coating failure.

For a long time, the use of hydrostatic testing was considered the only reliable way to prove the integrity of a pipeline that was a candidate for SCC attack. This type of test is expected to show all critical cracks, i.e. cracks that could cause failure under normal operating conditions. However, since no information on sub-critical cracks is obtained the estimation of the safe future service life becomes rather uncertain. Moreover, hydrostatic testing can cause crack growth of near critical cracks thus reducing the expected safety margin. Additionally, hydrostatic tests are expensive and time consuming, as the line has to be taken out of service.

Cracks have proved to be the most difficult to detect. There currently is no commercially available in-line inspection system with proven crack detection capacity. However, BG (formerly British Gas) has developed a pig-based system to detect and size longitudinal cracks and has reported some success.

MFL Pigs: Longitudinal flaws are difficult to detect by magnetic flux leakage (MFL) due to the physical principle used.

UT Pigs: Ultrasonic tools cannot recognize cracks oriented in a radial direction and can only detect cracks in a circumferential and longitudinal direction if the defect size is larger than about 5 mm in length.

A method, which utilizes elastic waves at ultrasonic frequency, has also been developed. Ultrasonic waves are injected into the pipe wall so that they travel circumferentially around the pipe and are detected when they are reflected from axial cracks. Elastic waves are transmitted in both directions to allow a comparison of echoes from both sides of the reflector.

The following additional comments can be made with respect to the techniques used in smart pigs:

1. **Low Resolution Magnetic Leakage Tools:**

   These smart pigs have been around for some time, and have produced satisfactory results for many pipeline operators. While unable to differentiate between internal and external defects, they can detect the majority of defects in pipelines. Costs for this tool typically run between \$600 and \$1200 per mile.

2. **High Resolution Magnetic Leakage Tools:**

   A more costly new alternative for pipeline operators, "high-resolution" MFL tools, come in limited sizes. Cost for this tool typically will cost \$1,500 to \$4,000 per mile.

3. **Ultrasonic Tools:**

   These smart pigs use ultrasonic technology to measure remaining pipe wall thickness. Until very recently these smart pigs have not been able to inspect thin-wall pipe (≤0.25 inches). Even now, the technology for inspecting thin walls is somewhat difficult. There are other limitations with this type of tool, such as requiring a couplant, being unable to detect small pits with sharp wall shapes, etc., which may be a factor for operators.

There are other techniques being developed, as noted below, but these are not yet available commercially or are still at the research stage:

- The techniques currently under development are ultrasonic and electromagnetic, specially the Remote Field Eddy Current (RFEC) method. In gas lines it is difficult to couple ultrasonic energy efficiently into and from the pipe wall; signal processing, or rather discrimination, is also proving to be a serious problem, partly because of the relatively small number of sensors which can be used. Whilst results from high resolution ultrasonic detection tools in liquid lines are encouraging, there is resistance to the use of liquid slugs in gas lines, although more valuable data is obtained than from a simple hydrostatic test.

- The Alternating Current Field Measurement (ACFM) crack detection and sizing technique has demonstrated its potential as a stress corrosion cracking (SCC) characterization tool.

- The SwRI techniques are termed SLIC, which refers to the simultaneous use of shear and longitudinal waves to inspect and characterized flaws. The techniques were developed in the 1980s and early 1990s.

  Four techniques using the SLIC systems were evaluated for sizing cracks: amplitude-drop, phase-comparison, peak-echo, and satellite-pulse. Each technique was calibrated against four electro-discharge machined (EDM) axial notches placed in one of the test specimens. The amplitude drop technique was used for estimating the crack lengths. The phase-comparison technique in conjunction with the peak-echo and satellite-pulse techniques were used for depth.

- MFL has been shown to be capable of detecting some mechanical damage. Part of the signal generated at mechanical damage is due to geometric change, for example, a reduction in wall thickness due to metal loss causes an increase in measured flux and sensor/pipe separation. Other parts of the signal are due to change in magnetic properties that result from stresses, strains, or damage to the microstructure of the steel.

4.4 In-Service External Inspection

External surveillance of pipelines can provide a wide range of data on various parameters that may affect pipeline integrity. A surveillance operation may involve the inspection of an entire pipeline using side scan sonar for example, or it may be restricted to monitoring a known critical area by a diver or a ROV.

During external surveillance, the following parameters can be inspected:

Location of pipelines
Seabed movement
Concrete weight coating condition
Corrosion protection system, and
Detection and location of leaks.

Visual observation is the most obvious form of external surveillance. The common equipment and techniques of external surveillance are as follows:

A. **Magnetometer and gradiometers**: These are mainly used for locating and tracking pipelines.

B. **Acoustics**: Typical applications include side scan sonar and sub-bottom profilers which are primarily used for the location and tracking of pipeline.

C. **Conventional Optics**: These include direct visual contact through the eyes of a diver and indirect contact through still photography and/or video cameras. Both direct and indirect visual contacts can be significantly affected by the underwater environmental, such as lighting and turbidity conditions.

D. **Unconventional Optics**: This uses a scanning laser light beam and is characterized by greater independence from underwater visibility conditions than conventional optic system.

E. **Cathodic Protection Survey Methods**: These include fish/trailing wire, ROV assisted remote electrode; ROV assisted trailing wire and electric field gradient.

In addition, a pig-based system using neutron absorption is being developed to find free spans and loss of concrete coating (see Reference 259, summarized in Appendix B).

4.5 Codes and Standards

4.5.1 API 570

API 570 covers inspection, repair, alteration, and re-rating procedures for metallic piping system that have been in-service. API 570 was developed for the petroleum refining and chemical process industries but may be used, where practical, for any piping system. It is intended for use by organizations that maintain or have access to an authorized inspection agency, a repair organization, and technically qualified piping engineers, inspectors, and examiners.

Risk-Based Inspection:

Identifying and evaluating potential degradation mechanisms are important steps in an assessment of the likelihood of a piping failure. However, adjustments to inspection strategy and tactics to account for consequences of a failure should also be considered. Combining the assessment of likelihood of failure and the consequence of failure are essential elements of risk-based inspection (RBI). The likelihood assessment must be based on all forms of degradation that could be expected to affect piping circuits in any particular service. The effectiveness of the inspection practices, tools and techniques utilized for finding the expected and potential degradation mechanism must be evaluated.

Specific attention is needed for inspection of piping systems that are susceptible to the following types and areas of deterioration:

A. Injection point

Injection points are sometimes subjected to accelerated or localized corrosion from normal or abnormal operating conditions. The preferred methods of inspecting injection points are radiography and/or ultrasonic, as appropriate, to establish the minimum thickness at each thickness measurement location (TML). Close grid ultrasonic measurement or scanning may be used, as long as temperatures are appropriate.

B. Deadlegs

The corrosion rate in deadlegs can vary significantly from adjacent active piping. The wall thickness on selected deadlegs should be monitored.

C. Corrosion Under Insulation

The most common forms of CUI are localized corrosion of carbon steel and chloride stress corrosion cracking of austenitic stainless steels. Locations where insulation plugs have been removed to permit piping thickness measurements on insulated piping should receive particular attention. These plugs should be promptly replaced and sealed.

D. Soil-to-air interfaces

Soil-to-air interfaces for buried piping without adequate cathodic protection shall be included in scheduled external piping inspections. Inspection at grade should check for coating damage, bare pipe, and pit depth measurement.

E. Service-Specific and Localized Corrosion

An effective inspection program help to identify the potential for service-specific and localized corrosion and select appropriate TML's.

F. Erosion and Corrosion/Erosion

Erosion can be defined as the removal of surface material by the action of numerous individual impacts of solid or liquid particles. It can be characterized by grooves, round holes, waves, and valleys in a directional pattern. A combination of erosion and corrosion results in significantly greater metal loss than can be expected from corrosion or erosion alone. Areas suspected of having localized corrosion/ erosion should be inspected, using appropriate NDE methods that will yield thickness data over the wide area, such as ultrasonic scanning, radiographic profile, or eddy current.

G. Environmental Cracking

Environmental cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydrogen blistering and hydrogen induced cracking (HIC). The inspection can take the form of surface NDE [liquid penetrant testing (PT), wet fluorescent magnetic-particle testing (WFMT) or ultrasonics (UT).

H. Corrosion Beneath Linings and Deposits

The effectiveness of corrosion-resistant lining is greatly reduced if there are breaks or holes in the lining. The linings should be inspected for separation, breaks, holes, and blisters. Large lines should have the deposits removed in selected critical areas for spot examination. Smaller lines may require that selected spools be removed or that NDE methods, such as radiography, be performed in selected areas.

I. Fatigue Cracking

Fatigue cracking of a piping system may result from excessive cyclic stress that are often well below that static yield strength of the material. Preferred NDE methods of detecting fatigue cracking include liquid-penetrant testing, or magnetic-particle testing. Acoustic emission also may be used to detect the presence of cracks that are activated by test pressure or stresses generated during the test.

J. Creep Cracking

Creep is dependent on time, temperature, and stress. Creep cracking may eventually occur at design conditions, since some piping codes allowable stresses are in the creep range. NDE methods of detecting creep cracking include liquid-penetrant testing, magnetic-particle testing, ultrasonic testing, radiographic testing and in-situ metallography. Acoustic emission testing also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

Types of Inspection and Surveillance

a. Internal visual Inspection
b. Thickness measurement Inspection
c. External visual Inspection
d. Vibrating piping Inspection
e. Supplemental Inspection

Internal Visual Inspection

Internal visual inspections are not normally performed on piping. When possible and practical, internal visual inspection may be schedule for systems such as large-diameter transfer lines, ducts, catalyst lines, or other large-diameter piping lines.

Thickness Measurement Inspection

A thickness measurement inspection is performed to determine the internal condition and remaining thickness of the piping components. Ultrasonic thickness measuring instruments usually are the most accurate means for obtaining thickness measurements on installed pipe larger than NPS 1. Radiographic profile techniques are preferred for pipe diameter of NPS 1 and smaller. Radiographic profile techniques may be used for locating areas to be measured, particularly in insulated systems or where non-uniform or localized corrosion is suspected. Where practical, ultrasonics can then be used to obtain the actual thickness of the area to be recorded.

When corrosion in a piping system is non-uniform or the remaining thickness is approaching the minimum required thickness, additional thickness measuring may be required. Radiography and/or ultrasonic scanning are the preferred methods in such cases. Eddy current devices also may be used.

External Visual Inspection

An external visual inspection is performed to determine the condition of the outsides of the piping, insulation system, painting and coating systems, and associated hardware; and to check for signs of misalignment, vibration, and leakage.

Vibrating Piping and Line Movement Surveillance

Vibrating or swaying piping, and other significant line movements should be reported that may have resulted from liquid hammer or liquid slugging in vapor lines.

Supplemental Inspection

Other inspections may be scheduled as appropriate or necessary. Periodic use of radiography and/or thermography, to check for fouling or internal plugging, may be implemented. Thermography may also be used to check for the hot spots in refractory lined systems, or inspection for environmental cracking. Acoustic emission, acoustic leak detection, and thermography can be used for remote leak detection and surveillance. Ultrasonics and/or radiography can be used for detecting localized corrosion.

Inspection of Welds In Service

Inspection for piping weld quality is normally accomplished as a part of the requirements for new construction, repairs, or alterations. However, welds are often inspected for corrosion as part of a radiographic profile inspection or as part of internal inspection. On occasion, radiographic profile examinations may reveal what appear to be imperfections in the weld. If crack-like imperfections are detected while the piping system is in operation, further inspection with weld quality radiography and/or ultrasonics may be used to assess the magnitude of the imperfections.

Inspection of Buried Piping

Inspection of buried process piping is different from other process piping inspection because significant external deterioration can be caused by corrosive soil conditions. Since the inspection is hindered by the inaccessibility of the affected area of the piping, the inspection of buried piping is treated in a separation section.

Smart pigging, Video Camera, Excavation are inspection methods.

4.5.2 <u>DNV 1996</u>

The in-service inspections are to be carried out according to accepted procedures. A long-term inspection program is to be established for the whole pipeline system. The program is to take into account the following:

- Inspection type
- Design and function of the pipeline system
- Seabed and environmental conditions
- Protection and burial requirements
- Corrosion and erosion condition
- Third party traffic density and extent
- Experience from previous inspections
- Possible consequences of failure.

Both external and internal inspection by smart pigging, if selected for metal loss inspection or other reasons, shall be included in the long term inspection program. The inspection program and further updating is to be agreed for each pipeline system.

External Corrosion Inspection

For risers, corrosion damage may occur in the splash zone and atmosphere zone due to damaged and/or disbonded coatings. Risers carrying hot fluids are most exposed to corrosion. In the submerged zone, certain coating malfunctions are not critical unless they are combined with deficiency in the cathodic protection system.

Inspection by special internal tools may be used to detect severe external corrosion of riser in all three zones. To a large extent external corrosion protection of pipeline and risers with sacrificial anodes can be limited to monitoring the condition of anodes. Electric field gradient measurements in the vicinity of anodes may be used for semi-quantitative assessments of anode current outputs.

Internal Corrosion Inspection

Inspection of internal corrosion is carried out in order to confirm the integrity of the pipeline system. Corrosion monitoring does not normally give any quantitative information of critical loss of wall thickness. Internal corrosion inspection of pipeline is typically carried out using an instrumented pipeline Inspection Gauge. Systems for wall thickness measurement based on magnetic flux leakage detection, ultrasonic examination, or eddy current techniques may be considered.

4.5.3 API 1104

The company shall have the right to inspect all welds by nondestructive means or by removing welds and subjecting them to mechanical tests. The inspection may be made during or after the welds has been completed.

Nondestructive testing may consist of radiographic inspection or other methods. The method used shall produce indications of defects that can be accurately interpreted and evaluated.

Nondestructive testing method:

Radiographic, magnetic particle, liquid penetrant, and ultrasonic test. The acceptance standards for the methods are different to different testing methods.

Acceptance standards given in Section 6 of the code are based on empirical criteria for workmanship and place primary importance on flaw length. Such criteria have provided an excellent record of reliability in pipeline service for many years. The use of fracture mechanics analysis and fitness-for-purpose criteria is an alternative method of determining acceptance standards and incorporates evaluation of the significance of both flaw depth and flaw lengths. The fitness-for-purpose criteria provide more generous allowable flaw sizes, but only when additional procedure qualification tests, stress analysis, and inspections are performed.

4.5.4 ASME B31.8

Welding and Inspection Tests

100% of the total number of circumferential field butt welds on offshore pipelines shall be non-destructively inspected, if practical, but in no case shall less than 90% of such welds be inspected.

All welds which are inspected must meet the standards of acceptability of API 1104. For girth welds on a pipeline, alternative flaw acceptance limits may be established based upon fracture mechanics analysis and fitness-for-purpose criteria as describe in API 1104. Such alternative acceptance limits shall be supported by appropriate stress analysis, supplementary welding procedure test requirements, and non-destructive examination beyond the minimum requirements specified in API 1104.

4.5.5 BS 8010

Weld Inspection

Selection of the appropriate weld inspection technique, acceptance criteria and the frequency of inspection should conform to the relevant welding standard. Typical inspection techniques and standards are visual inspection (BS 5289); Magnetic Particle Inspection (BS 6072); Dye Penetrant (BS 6443); Radiographic Inspection (BS 2600); Ultrasonic Inspection (BS 3923).

4.5.6 CSA Z662

Inspection:

Pipe and components shall be inspected for defects. Such inspection shall include, but not necessarily be limited to, inspection for flattening, ovality, straightness, pits, slivers, cracks, gouges, dents, defective weld seams, and defective field welds.

Where the pipe is field-coated, inspection shall be carried out to determine that the cleaning/coating machine is not creating defects in the pipe.

Where necessary and as appropriate, nondestructive inspection of piping shall be performed using one or more of the following:

a. Radiographic inspection of welds
b. Ultrasonic inspection of welds
c. Ultrasonic inspection of pipe
d. Electrical inspection of protective coatings
e. Inspection using internal inspection devices
f. Other methods capable of achieving appropriate results.

Inspection and Testing of Production Welds

All welds within the limits of uncased road and railway crossings, all welds within the limits of water crossings, all pressure-containing welds that will not be pressure tested in place, and a minimum of 15% of all production welds made each day shall be non-destructively inspected: 1) for 100% of their lengths; 2) in accordance with the requirements of Clause 7.2.8.3; and 3) where such welds are butt welds, using radiographic or ultrasonic methods, or a combination of such methods.

Radiography

Source of radiation shall be X-ray machines or radioisotopes. The radiation source shall be located either inside or outside the pipe or component. Where radiation sources are located on the outside, the image of one or both walls shall be acceptable for interpretation.

Ultrasonic Inspection of Pipeline Girth Welds

Imperfections recorded by ultrasonic inspection (i.e. weld conditions giving indications that exceed the recording level) shall be as follows:

1. Imperfections characterized as cracks shall be unacceptable regardless of length or location.

2. Individual imperfections that are determined not to extend into the weld beads closest to the surfaces of the pipe shall not exceed 50 mm in length, the cumulative length of such imperfection in any 300 mm length of welds shall not exceed 50 mm, except that for welds less than 300mm long, the cumulative length of such imperfection shall not exceed 16% of the weld length.

3. Individual imperfections other than those covered by Items 1,2 shall not exceed 12 mm in length, and the cumulative length of such imperfections in any 300 mm length of weld shall not exceed 25 mm, except that welds less than 300 mm long, the cumulative length of such imperfections shall not exceed 8% of the weld length.

Guidelines for In-Line Inspection of Piping for Corrosion Imperfections

The factors to be reviewed when considering such inspection techniques should include, but not necessarily be limited to, the following:

a. the availability and capability of the equipment
b. the age, condition, and configuration of the piping
c. the service, leak, and corrosion mitigation history of the piping
d. population density and environmental concerns.

5. PIPELINE DEFECT ASSESSMENT METHODS

5.1 Assessment of Weld Defects

5.1.1 API 1104

This standard covers the gas and arc welding of butt, fillet, and socket welds in carbon and low alloy steel piping used in the compression, pumping, and transmission of crude petroleum products and fuel gases and, where applicable, covers welding on distribution systems. This standard also covers the acceptance standards to be applied to production welds tested to destruction or inspected by radiography. It includes the procedure for radiographic inspection.

The document presents acceptance standards for non-destructive testing, which apply to discontinuities located by radiographic, magnetic particle, liquid penetrant, and ultrasonic test methods. These acceptance standards are based on empirical criteria for workmanship and place primary importance on flaw length. Such criteria have provided an excellent record of reliability in pipeline service for many years.

In addition, API 1104 allows the use of alternative fitness-for-purpose criteria based on fracture mechanics analysis, which incorporates evaluation of the significance of both flaw depth and flaw length. The fit-for-purpose criteria provide more generous allowable flaw sizes, but only when additional procedure qualification tests, stress analysis, and inspections are performed. Figure 5.1 presents a flowchart for the steps required to perform the checks.

The method requires that the welding procedures are qualified for either of two minimum CTOD toughness levels: 0.005 inch or 0.010 inch. Then, for a given maximum applied strain, the allowable defect depth is inferred. Limits on defect length are dependent on defect depth.

A residual strain of 0.2% has been included in developing the acceptance criteria in order to account for postulated residual stresses of yield magnitude. Defect depth may be determined by NDT techniques or by consideration of inherent size limitations due to weld pass geometry.

5.1.2 BS 7910

As the replacement of PD 6493 and PD 6539, this code outlines methods for assessing the acceptability of flaws in all types of structures and components. Although emphasis is placed on welded fabrications in ferritic and austenitic steels and aluminum alloys, the procedures developed can be used for analyzing flaws in other materials and in non-welded applications.

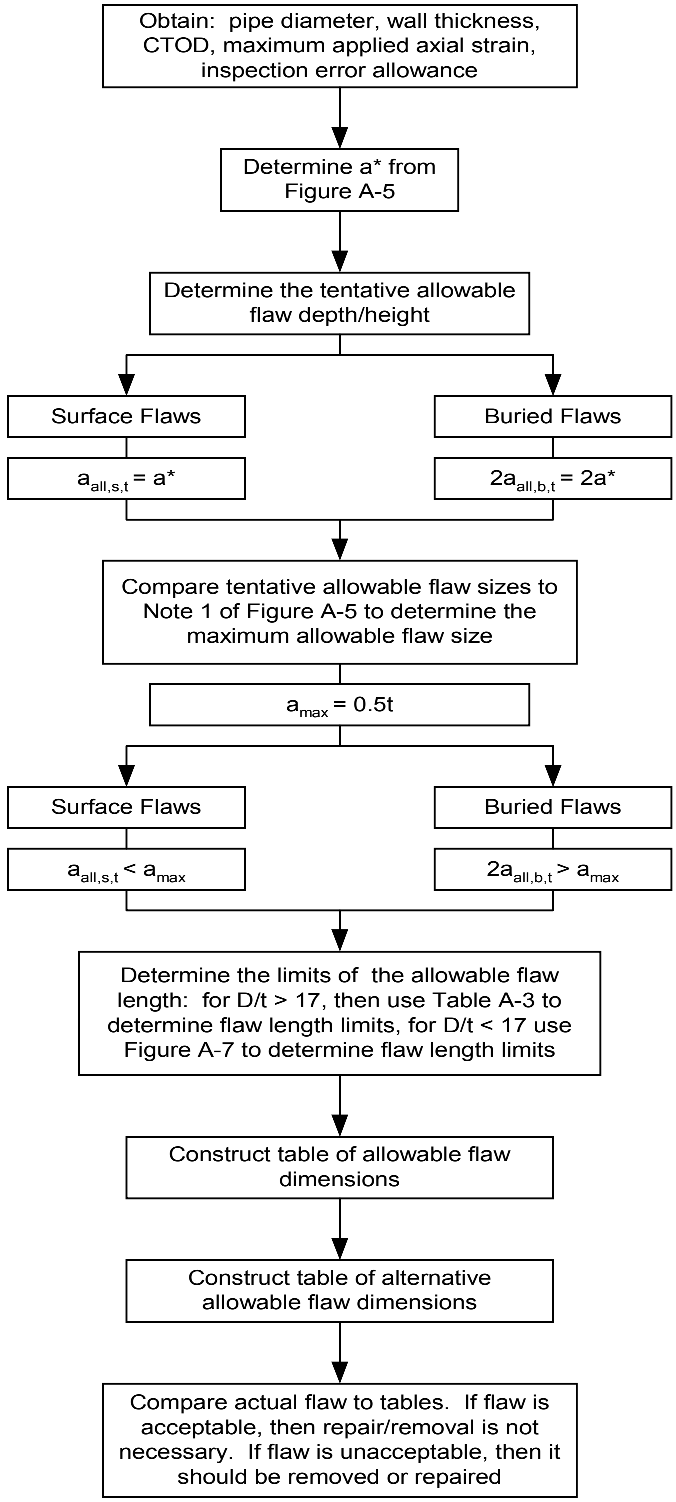

Figure 5.1: API 1104 Girth Weld Defect Assessment Procedure

The fracture assessment procedures described in BS7910 are a development of the 1991 edition of PD 6493. Although there are continuing advances and improvements in fracture assessment methods, the procedures presented are felt to represent approaches which have been validated extensively and are intended to provide consistently accurate and safe predictions. They combine the Crack Tip Opening Displacement Methods introduced by the Welding Institute via the 1980 edition of PD6493 with approaches based on the R6 procedures published by Nuclear Electric/Magnox Electric (formerly Central Electricity Generating Board) in the UK.

The code contains improvements to the approaches in PD6493: 1991 based on user experience, additional solutions and improved guidance from various literature sources, and a fuller integration of R6 Rev 3 procedures.

As in the 1991 edition of PD 6493, three levels of fracture assessment are available to the user. All levels refer to tensile Mode I failure only. Shear failure is dealt with in the method in Annex B. All three levels of assessment use a Failure Assessment Diagram (FAD), which combines consideration of fracture and local plastic collapse. The choice of level depends on the input data available, the level of conservatism and the degree of complexity required.

Level I: this is the screening level introduced into the 1991 version of PD6493 and broadly compatible with the 1980 edition of the document. This level provides a conservative estimate from its use of the simplified FAD with in built safety factors and required conservative estimates of the applied stress, residual stress and fracture toughness.

Level II: this is considered to be the normal assessment route applicable for general structural steel application and makes use of a more accurate FAD with no inherent safety factors. The procedure permits the prediction of acceptability of the structure when all three input parameters are known and also allow limiting values of any one parameter to be predicted.

Level III: This level employs a full tearing instability approach and therefore provides a more accurate description of the performance of ductile materials.

Approach

The pipe outer diameter (D), wall thickness (B), dent depth (a), dent length (2c), yield and ultimate stresses (σ_Y and σ_U), Charpy impact energy value (C_v) or fracture toughness value (K_{mat}) need to be known to use this method. The steps below describe a Level 2 analysis (normal analysis) and are illustrated in the flowchart shown in Figure 5.2.

1. Define the stresses acting on the pipeline. The primary stress (P) includes all stresses caused by internal pressure and external loads (P_m (membrane stress) and P_b (bending stress) are components of P). Secondary stresses (Q) are self-equilibrating stresses and the peak stress (F) is the increment of stress that is added to P and Q due to local discontinuity.

2. If fracture toughness values (K_{mat} or σ_{mat}) are available, then carry on to Step 3. If this information is not available, then the Charpy V-notch energy can be used to determine K_{mat} with the correlation from Figures E1 and E2 of BS7910.

3. Determine the material tensile properties (material yield strength (σ_Y), tensile strength (σ_u) and modulus of elasticity (E)).

4. Characterize the flaw. Determine if the flaw is planar, non-planar or a shape imperfection, and if the flaw is through-thickness, surface or embedded. For surface flaws, the depth (a) and the length (2c) should be known.

5. Select the failure assessment diagram (FAD) to be used for assessment (generalized or material specific). The failure assessment diagram should be calculated at least at values of Lr = 0.7, 0.9, 0.98, 1.00, 1.02, 1.10...to Lr_{max}. Where $Lr_{max} = \sigma_f/\sigma_Y$ and $\sigma_f = 1/2(\sigma_Y+\sigma_u)$. For the generalized curve, the FAD is given by the following equation:

$$K_r = \left[1 - 0.14 L_r^{\,2}\right] * \left[0.3 + 0.7\exp\left(-0.66 L_r^{\,6}\right)\right] \text{ for } L_r < L_{rmax}$$

or $K_r = 0$ for $L_r > L_{rmax}$.

For the material specific curve, the FAD is given by the following equation:

$$K_r = \left[\frac{\varepsilon_{ref} E}{L_r \sigma_Y} + \frac{\sigma_Y L_r^3}{2E\varepsilon_{ref}}\right]^{-0.5} \text{ for } L_r < L_{rmax}$$

or $K_r = 0$ for $L_r > L_{rmax}$.

6. Calculate the data Lr using the following equation:

$$L_r = \frac{\sigma_{ref}}{\sigma_Y}$$

where $\sigma_{ref} = 1.2 M_s P_m$; $M_s = 1 - \dfrac{\dfrac{a}{BM_t}}{1 - \dfrac{a}{B}}$; and $M_T = \left[1 + 1.6\dfrac{c^2}{r_i B}\right]^{0.5}$

7. Calculate the data Kr using the following equation:

$K_r = \dfrac{K_I}{K_{mat}}$ where $K_I = (Y\sigma)\sqrt{a\pi}$ where $(Y\sigma)$ is determined using equations and tables in Annex J of BS7910.

8. Plot data assessment points on FAD.

9. Compare plotted points to FAD. If the points are below the FAD curve, then the defect is acceptable. If the points are above the curve, then the defect is unacceptable and the pipe should be repaired or replaced.

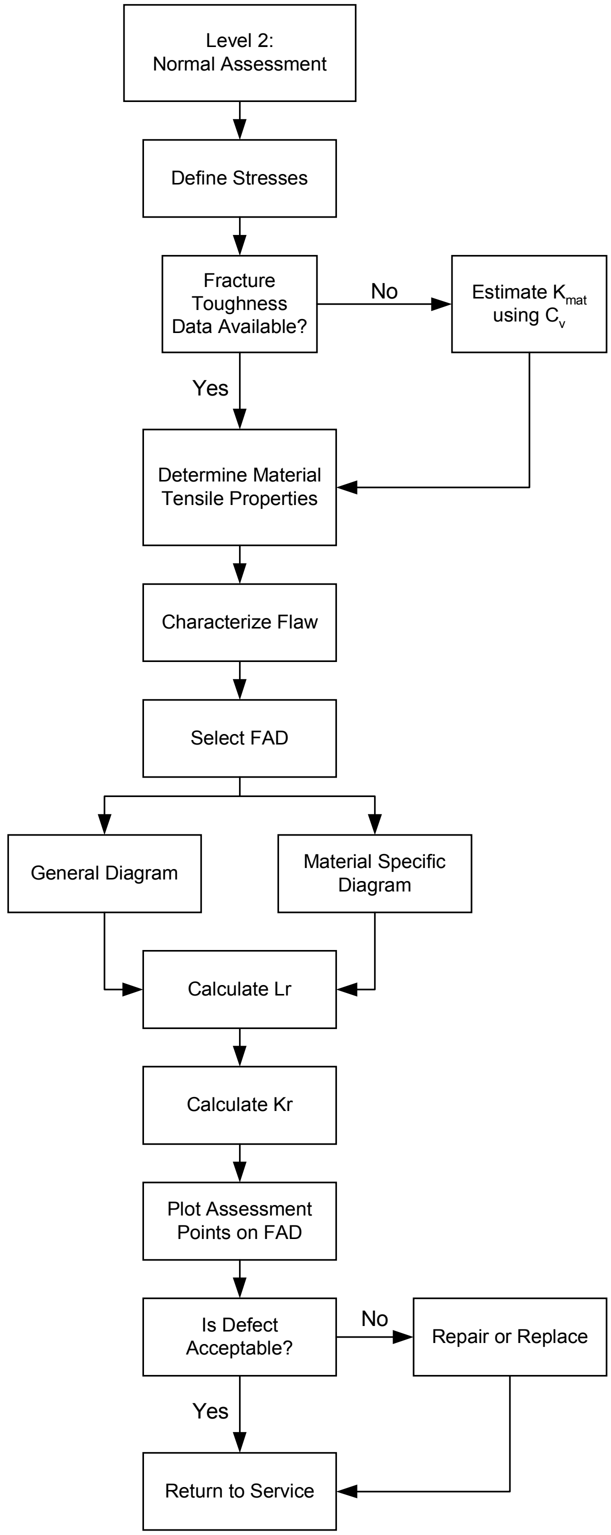

Figure 5.2: BS7910 Assessment Procedure

5.1.3 CSA Z662-99

Work quality standards of acceptability have been based on experience with traditional welding and inspection practices. This experience has indicated the capabilities of welding procedures and personnel in minimizing the incidence of welding imperfections during production welding of pipe girth welds.

Appendix J of the code outlines the application of the concept of engineering critical assessment to fusion welds. Standards of acceptability based on Engineering Critical Assessment (ECA) include consideration of the measured weld properties and intended service conditions for a specific application. Alternatives to the work quality standards of acceptability can be derived for sections of a new pipeline.

Appendix K of the code provides the analytical methods that shall be used to derive standards of acceptability for weld imperfections, which may be used as an alternative to the standards. The standards of acceptability that are derived are based on engineering critical assessment and include consideration of the measured weld properties and the intended service conditions.

5.1.4 R/H/R6 Revision 3

R/H/R6 was originally published as a Central Electricity Generating Board (CEGB) Report entitled " Assessment of the Integrity of Structures Containing Defects" in 1976. The R6 defect assessment procedure uses the concept of a failure assessment diagram (FAD) to define the boundary between the safe and unsafe operating conditions of the flawed structures.

The procedure described in the main document adopts a deterministic approach in which specific combinations of defect size and material property values are chosen to ensure a conservative result in the assessment of defect structures. The elastic-plastic assessment procedure used in the R6 approach can form the basis of a probabilistic assessment procedure where the uncertainties in the main assessment parameters are included. In Appendix 10 of R6, a probabilistic assessment procedure based on the R6 analysis is described which takes account of developments in probabilistic fracture mechanics in recent years. This extends previous applications of probabilistic fracture mechanics, which have been based mainly on linear elastic fracture mechanics, to elastic-plastic fracture analysis more appropriate for the assessment of general engineering structures.

Approach

The R/H/R6 method offers three categories of analysis based on the type of information available. The information required for assessment is similar to that of BS7910 which includes: pipe outer diameter (D), wall thickness (t), dent depth (a), dent length (l), yield and ultimate stresses (σ_Y and σ_U), Charpy impact energy value (C_v) or fracture toughness value (K_{mat}). The steps below depict a Category 1 analysis. The flowchart for this method is shown in Figure 5.3 below.

1. Define and categorize the loads and stresses acting on the pipeline (σ^p from loads contributing to plastic collapse and σ^s from loads which do not contribute to plastic collapse).

2. Determine the material tensile properties (material yield strength (σY), tensile strength (σu) and modulus of elasticity (E)).

3. Select and define failure assessment diagram (FAD). The failure assessment diagram should be calculated at least at values of L_r = 0.7, 0.9, 0.98, 1.00, 1.02, 1.10 .....to L_{rmax}. Where $L_{rmax} = \sigma_f/\sigma_Y$ and $\sigma_f = 1/2(\sigma_Y+\sigma_u)$. For the generalized curve, the FAD is given by the following equation:

   $K_r = [1 - 0.14 L_r^{\,2}] * [0.3 + 0.7 \exp(-0.66 L_r^{\,6})]$ for $L_r<L_{rmax}$ or $K_r=0$ for $L_r>L_{rmax}$.

   For the material specific curve, the FAD is given by the following equation:

   $$K_r = \left[\frac{\varepsilon_{ref} E}{L_r \sigma_Y} + \frac{\sigma_Y L_r^3}{2E\varepsilon_{ref}}\right]^{-0.5}$$ for $L_r<L_{rmax}$ or $K_r=0$ for $L_r>L_{rmax}$.

   For the J-integral curve, the FAD is given by the following equation: $K_r = \left(\frac{J_e}{J}\right)^{0.5}$ for $L_r<L_{rmax}$ and $K_r=0$ for $L_r>L_{rmax}$ where J_e and J are values corresponding to the same load (same L_r) and K_r is plotted as a function of L_r.

4. Characterize the flaw shape (determine the defect depth (a) and the defect length (l)).

5. Select the category of analysis depending on information available (Category 1 (simple), Category 2 (more advanced), Category 3 (advanced)).

6. Define the fracture toughness values (Kmat, □mat, or J). If information is not available, use BS7910 to determine fracture toughness values.

7. Calculate Lr using the equation:

   $$L_r = \frac{total\ applied\ load\ giving\ rise\ to\ \sigma^p\ stresses}{plastic\ yield\ load\ of\ the\ flawed\ structure}$$

   where the $plastic\ yield\ load = \dfrac{\sigma_Y}{\sigma_f} * p_L$

   and the plastic collapse load (p_L) is calculated from:

   $$p_L = \left(\frac{\sigma_f t}{R}\right) * \left(1 + 0.4\frac{l^2}{Rt}\right)^{-0.5}$$ where R is the radius of the pipe

   and $\sigma_f = 1/2(\sigma_Y+\sigma_u)$ is the flow stress.

8. Calculate K_r using the following equations:

$$K_r = K_r^p + K_r^s \quad \text{where} \quad K_r^p = \frac{K_I^p}{K_{mat}} \quad \text{and} \quad K_r^s = \frac{K_I^s}{K_{mat}} + \rho$$

where K_I^p and K_I^s are the linear elastic stress intensity factors for loads giving rise to σ^p and σ^s stresses, respectively, and σ is determined from Figure A4.1 from R/H/R6.

9. Plot the data assessment points on the FAD.

10. Compare plotted points to FAD. If the points are below the FAD curve, then the defect is acceptable. If the points are above the curve, then the defect is unacceptable and the pipe should be repaired or replaced.

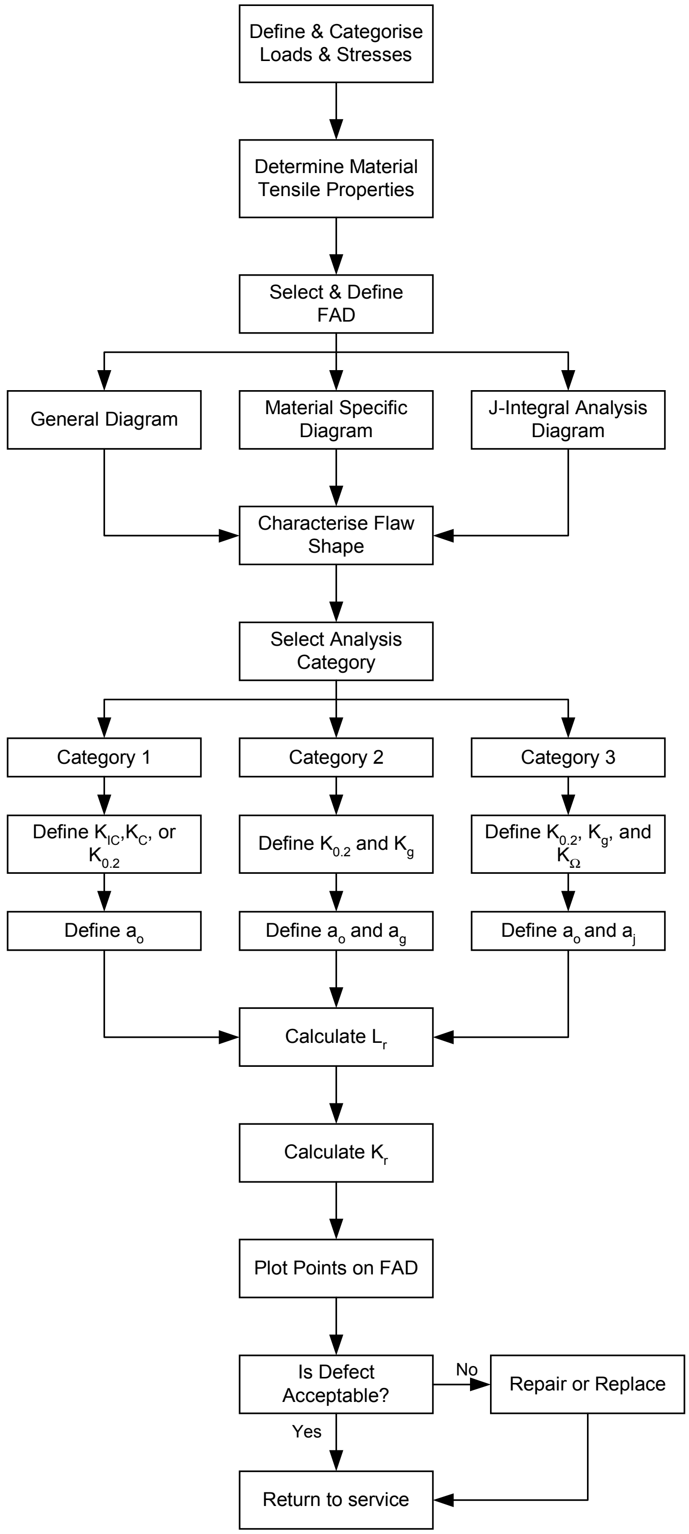

Figure 5.3: R/H/R6 Assessment Procedure

5.2 Assessment of Corrosion Defects

Figure 5.4 presents a list of methods available for corrosion defect assessment. The methods are grouped vertically by their type, codified methods or others, and horizontally by their applicability, pressure or combined loading etc. Assessment of codified methods is discussed in the following. Assessment of other methods, except for RSTRENG, was not feasible because of lack of information.

	Pressure Only		Combined Loading	
	Length and Depth	Area and Depth	Pressure and Bending	Pressure, Bending, Axial Compression
Coded Methods	ASME B31G			
	DNV F101	DNV F101	DNV F101	DNV F101
Other Methods	RSTRENG 0.85	RSTRENG Effective	Bubenik FEM	
	Mok et al	Leis-PCORRC	SAFE-SwRi Stress Model	
	Hopkins		Andrew Correction Factor	
	Rosenfeld		Wang-SwRi Strain Model	

Figure 5.4: Methods for Corrosion Defect Assessment

5.2.1 ASME B31G

ASME B31G is a manual for evaluating the remaining strength of corroded pipelines. It is a supplement to the ASME B31 code for pressure piping. The manual was developed in the late sixties and early seventies at Battelle Memorial Institute and provides a semi-empirical procedure for the assessment of corroded pipes. Based on an extensive series of full-scale tests on corroded pipe sections, it was concluded that line pipe steels have adequate toughness and the *toughness* is not a significant factor. The failure of blunt corrosion flaws is controlled by their *size* and the flow stress or *yield stress* of the material.

Approach

Figure 5.5 presents a flowchart for the B31G method. Input parameters include pipe outer diameter (D) and wall thickness (t), the specified minimum yield strength (SMYS), the maximum allowable operating pressure (MAOP), longitudinal extent of corrosion (L_c) and defect depth (d). The procedure works as follows:

1. Compare the defect depth (d) to the nominal wall thickness of the pipe (t). If d/t is less than 10%, then pipe may remain in service after arresting corrosion. If d/t is greater than 80%, the pipe must be repaired or replaced before return to service. For values of d/t between 10% and 80%, carry on to Step 2.

2. Compare the measured longitudinal extent of corrosion (L) to the value from tables provided in the manual for (L_c) or from:

$$L_c = 1.12B\sqrt{Dt}$$

where D is the pipe outside diameter, t is the nominal wall thickness, and B is defined as:

$$B = \sqrt{\left[\frac{d/t}{1.1d/t - 0.15}\right]^2 - 1}$$

B may not exceed a value of 4. If L is equal to or less than L_c, then arrest further corrosion and return pipe to service. If L is greater than L_c, carry on to Step 3.

3. Compare MAOP to the maximum pressure (P') calculated from:

$$P' = 1.1P\left[\frac{1 - \frac{2}{3}\frac{d}{t}}{1 - \frac{2}{3}\left(\frac{d}{t\sqrt{A^2+1}}\right)}\right]$$ when A, defined below, is less than or equal to 4.0, or

$$P' = 1.1P\left(1 - \frac{d}{t}\right)$$ when A is greater than 4.0

P is the greater of the established MAOP *or* $P = 2(SMYS)tFT/D$ with F being the design factor and T being the temperature derating factor from the appropriate B31 code. A is defined as:

$$A = 0.893\left(\frac{L_m}{\sqrt{Dt}}\right)$$

where L_m is the measured longitudinal extent of the corroded area.

If the established MAOP is equal to or less than P', then arrest further corrosion and return the pipe to service. If the established MAOP is larger than P', repair or replace the section and return pipe to service or reduce the MAOP and return pipe to service.

Limitations

Limitations on the use of the B31G procedure include:

1. It applies to corrosion defects only in the body of the pipe which have relatively smooth contours and cause low stress concentration

2. It applies to pipes under internal pressure loading only.

The assessment procedure considers the maximum depth and longitudinal extent of the corroded area, but ignores the circumferential extent and the actual profile.

If the corroded region is found to be unacceptable, B31G allows the use of more rigorous analysis or a hydrostatic pressure test in order to determine the pipe remaining strength. Alternatively, a lower maximum allowable operating pressure may be imposed.

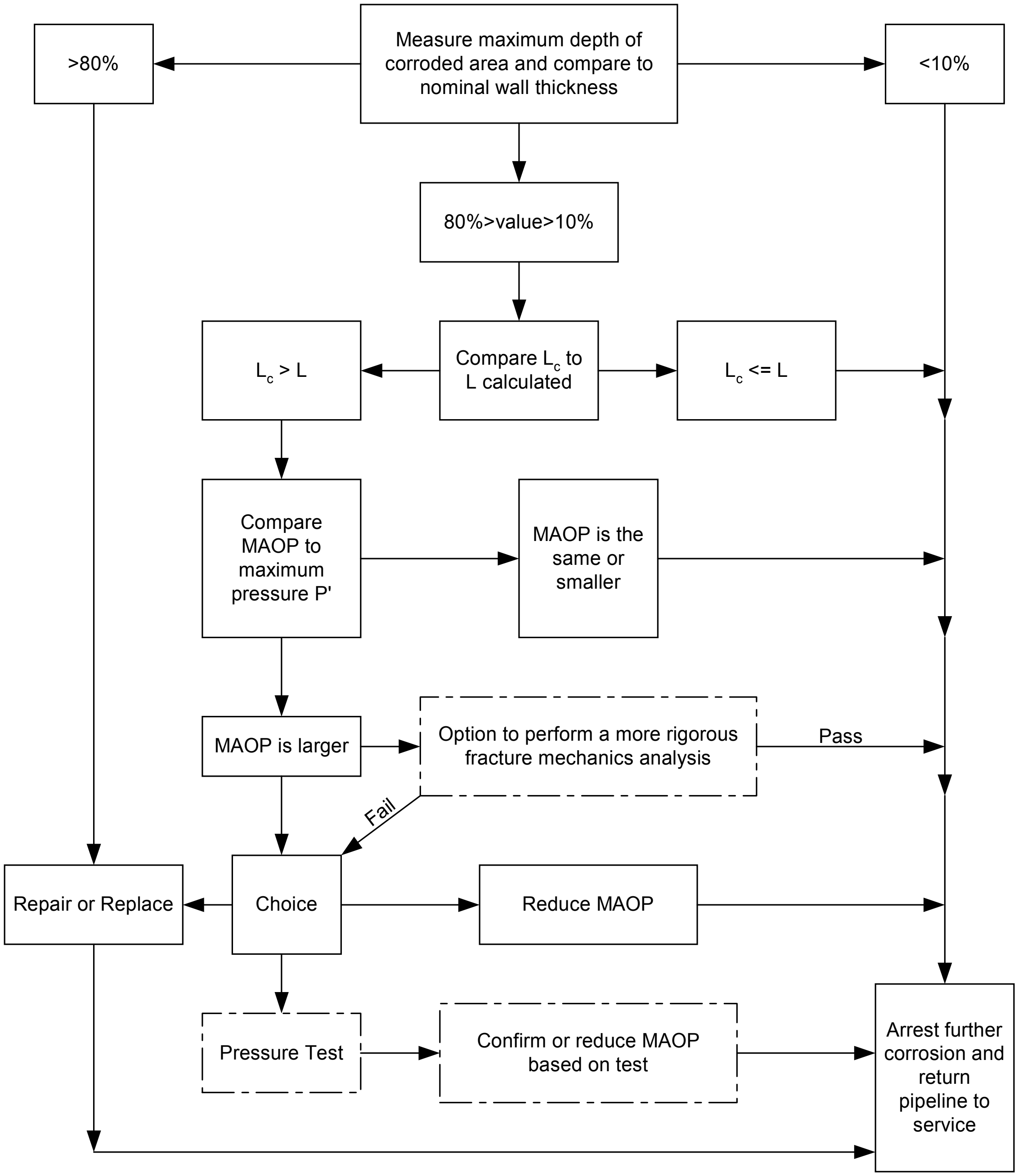

Figure 5.5: ASME B31G Assessment Procedure

5.2.2 DNV RP-F101

DNV RP-F101 is the first codified and comprehensive recommended practice on pipeline corrosion defect assessment. It provides guidance on single and interacting defects under pressure only and combined loading. The RP-F101 provides two methods of analysis: a partial safety factor method and an allowable stress design method. Both methods require information on the pipe outside diameter (D), wall thickness (t), ultimate tensile strength (UTS), MAOP, longitudinal extent of corrosion (L_c) and defect depth (d). The allowable stress design method considering non-interacting defects is discussed here. Exact procedures for the partial safety factor method and interacting defects can be found within the DNV code if needed.

Approach

The flowchart for this method is presented in Figure 5.5. The approach is as follows:

1. Determine type of loading on pipeline (pressure only or combined).

2. Calculate the failure pressure (P_f) using:

$$P_f = 2t\frac{UTS}{(D-t)}\frac{1-\frac{d}{t}}{1-\frac{d}{tQ}}$$

   where Q is calculated from the following equation and the other variables are as listed above:

$$Q = \sqrt{1+0.31\left(\frac{1}{\sqrt{Dt}}\right)^2}$$

3. Compare P_f to MAOP. If the MAOP is greater than P_f, then repair or replace the pipeline before returning to service. If the MAOP is less than P_f, arrest further corrosion and return pipeline to service.

5.2.3 RSTRENG

The RSTRENG software program is designed to evaluate the remaining strength of externally corroded pipe. This package offers three analyses for corroded pipelines: RSTRENG 0.85-Area method, RSTRENG Effective Area method and the ASME B31G method. As seen in Table 2.1, this software requires knowledge of the pipe outer diameter, wall thickness, specified minimum yield strength (SMYS), maximum allowable operating pressure (MAOP), longitudinal extent of corrosion, defect depth and a detailed corrosion profile. The following steps are required for analysis to be performed:

1. Create new file with inspector's name and pipe location.

2. Enter in new profile information: pipe outside diameter, wall thickness, SMYS, MAOP, and increment length.

3. On calculation page enter number of increments and pit depths from corrosion profile.

4. Press "calculate" button. The program will calculate the maximum safe pressure and burst pressure using the three methods of analysis.

5. Compare calculated pressure to actual pressure to determine if pipe should be repaired or replaced or remain in service as is.

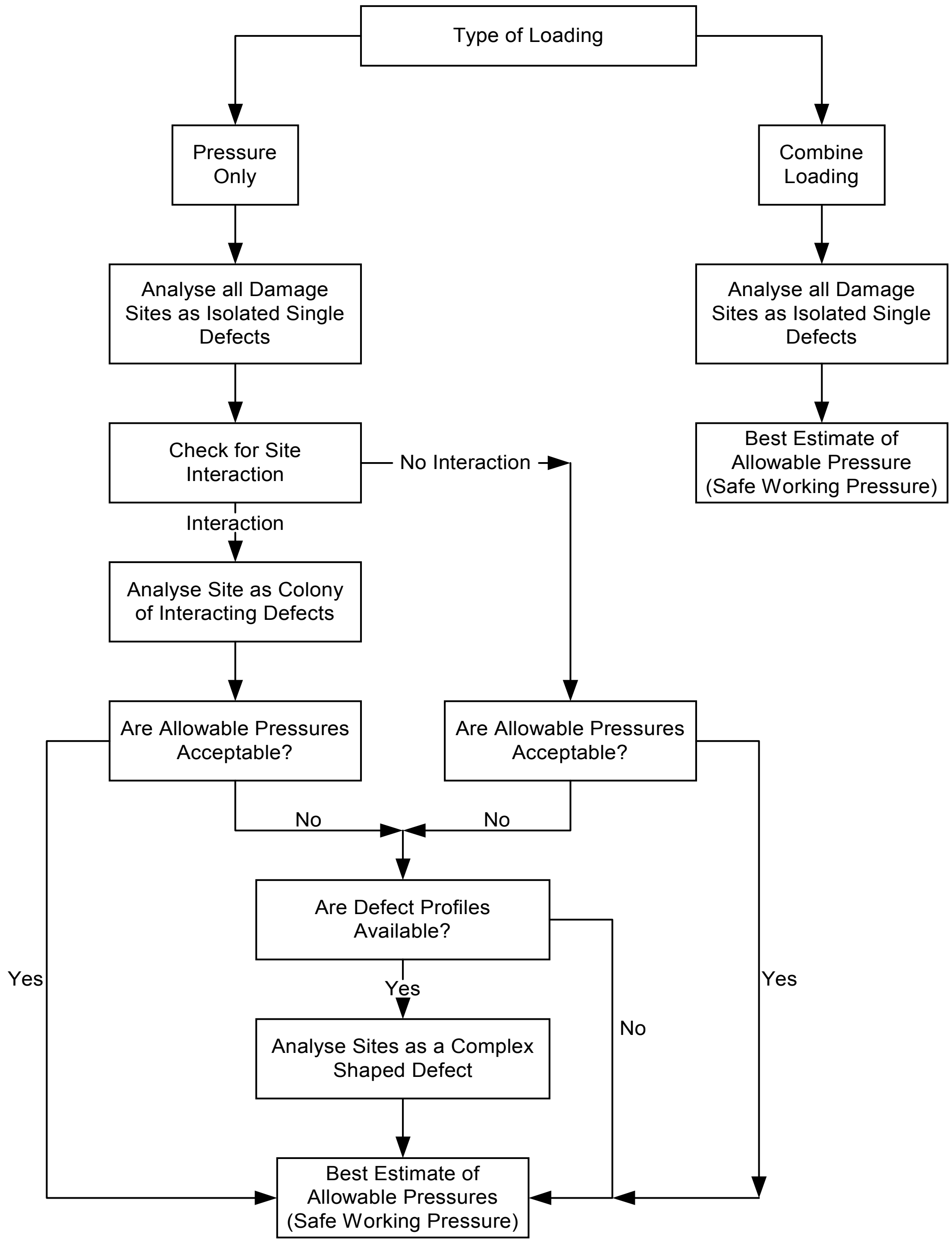

Figure 5.5 DNV RP-F101 Assessment Procedure

5.3 Assessment of Mechanical Damage

5.3.1 General

Damage due directly to contact with equipment, when inflicted by other than the owner of the pipeline, is known as "third-party" mechanical damage. Mechanical damage is usually localized at the point of contact and causes localized significant stresses and strains, and in some instances cracking. In most instances, mechanical damage does not cause immediate failure and is more likely to grow by stress-induced mechanisms, such as stable tearing, fatigue, or other time and/or cycle dependent processes. Third-party mechanical damages, therefore, go undetected most of the time and are more likely to lead to a delayed, often catastrophic failure. Gouges, dents and combinations of dents and other defects (e.g. gouges or cracks) are typical mechanical damage defects.

Gouges:

A conservative assessment of gouges may be based on idealizing these as surface planar defects and using any of the established procedures in connection with the assessment of weld planar defects such as BS7910 and R/H/R6 as discussed in section 5.1.

Dents:

Dented pipes develop high levels of local stress concentrations. In the presence of other discontinuities, such high stresses may cause a substantial reduction in the pipeline's tolerance to static and cyclic loads. In the absence of other defects, dents seem to have little effect on the burst strength of line pipe.

Behavior of Plain Dents:

(a) Plain, smooth dents of depth up to 8% and possibly 24% of pipe diameter have little effect on the pipe burst strength.

(b) High internal pressure due to operational loads or to a hydrostatic test may be beneficial since they push the dent out leading to a partial relief of the local stress concentration.

(c) Dents in pipelines subjected to large pressure fluctuations can exhibit fatigue lives below design requirements. Such dents should be assessed for fatigue failure.

(d) Plain dents which survive a hydrotest or are in high-pressure pipelines, are likely to have longer fatigue lives than dents introduced after a hydrotest or in low-pressure pipelines.

(e) Pipes with dented welds should be treated with extreme caution. They can exhibit low burst pressure and poor fatigue lives. This is mainly due to the weld being susceptible to crack-like defects introduced at the manufacturing stage or during the denting process.

Behavior of Combined Dents/Defects:

(a) This is the severest form of mechanical damage because it combines stress concentration due to the dent in addition to severe stress intensification due to a defect such as a gouge or a crack. The failure of a combined dent/defect in a pipe under increasing internal pressure involves outward movement of the dent and tearing of the defect through the wall. This failure mechanism of tearing within an unstable structure makes the quantification of such failure difficult.

(b) Combined dents/defects generally have poor fatigue properties. However, fatigue life increases at high mean stress in the fatigue cycle and as a result of a pre-service hydrotest. This is due to the high internal pressure pushing the dent out, thus reducing the stress concentration factor induced by the dent geometry.

(c) Fatigue data from tests show that increasing the dent depth from 2% to 4% of pipe diameter halves the fatigue life. Whereas increasing the defect depth from 10% to 20% of wall thickness reduces fatigue life by about a factor of 3.

5.3.2 Hopkins' Method

Hopkins proposed that gouges can be assessed using the same equation in relation to the assessment of corrosion defects and give simple acceptance levels for gouges based on his finding that pipe body defects of ductile steels do not generally pose a brittle fracture risk. Hopkins introduced two alternative safety factors into the acceptance levels. One is the factor of 2 on the gouge depth and another one corresponds to using 100% SMYS as the input which is equivalent to only allowing defects which would survive a hydrostatic test to this level. It should be noted that the equation Hopkins proposed accounts only for hoop stress due to internal pressure and with regard to corrosion defects, it seems that it only considers the longitudinal extent of the corroded area and ignores its circumferential dimensions. This may imply that in using this equation for assessing gouges in internally pressurized pipelines, only the length of the longitudinal projection of the gouge needs to be used rather than the actual length.

5.3.3 PRCI - Ductile Flow Growth Model (DFGM)

The Pipeline Research Committee International (PRCI) funded the development of this assessment model. The ductile flow growth model deals with failure from defects in otherwise undamaged line pipe. The model appears to be accurate as is evident from validation studies conducted at Battelle. The work conclusively demonstrated that numerical analysis of the effects of dents or dents with gouges must in general be done using material as well as geometric non-linearity in order to account for the essential effect of pressure stiffening on denting and re-rounding of the pipeline. The DFGM method has successfully predicted the failure behavior of field damage ranging from situations that are safe without rehabilitation, to situations leading to ruptures.

6. DATABASE

6.1 Database Requirements

A primary deliverable from this project is a database on the strength of pipelines containing defects. The usefulness of any database is very dependent on the care exercised during its development, particularly with such issues as completeness of captured data, screening, quality assurance and database structure.

MSL's experience in the area of database preparation would indicate that time spent during the initial set-up (i.e. in defining the fields of the database) pays dividends during data entry, data checking and eventual use. As an example, different source documents will use different units (e.g. inches v. millimeters) whereas the data in the database needs presenting in consistent units. However, to facilitate the checking of data entry against the source documents, it is easier to use the original unit systems of those documents. The database therefore contains a degree of duplicated columns; one set based on original units and the other with consistent units. After data entry checking, the columns with original units can be hidden for presentation purposes.

It is important to capture the data fully. For instance, the pipe thickness will normally be quoted but it may be relevant in subsequent analyses to know whether this value was nominal, measured or inferred (from other variables such as D and D/T). This information has therefore been carefully recorded. In a similar vein, the steel yield stress is preferably a measured value but may have been given in terms of the specified minimum value. Again, such information needs to be recorded, including both measured and specified values if available. The inclusion of a 'comment' field is essential for recording peculiar testing characteristics. In all cases, tabular information in the source documents is to be preferred over graphical information as the latter may introduce scaling errors when extracting data.

Consideration was given to setting up a number of separate databases according to defect type: dent, gouge, cracks, corrosion, etc. However, many of the fields would be common, e.g. fields describing pipe geometry, materials, loading, etc. It was therefore decided to generate a Master Database, subsets of which could be extracted later for subsequent appraisal. A detailed description of all fields is given in the next subsection.

6.2 Description of Fields

The fields defined in the Master Database are reproduced in Table 6.1. In the actual database, the field headings stretch along one horizontal line. The numbers in the first row refer to Notes given in Table 6.2.

See Note:					1	2			3			3	3	3			
SPECIMEN IDENTIFICATION							**PIPE GEOMETRY**										
Ref No	Author	Spec ID	Sequence No.	Type	Screening Level	Type of Defect	Dia (source)			Thk. (source)			D [mm]	T [mm]	D/T	L [mm]	L/D
								Unit	Type		Unit	Type					

4					3			3			3			3		
PIPE SPECIFICATION			**MATERIAL PROPERTIES**													
Manufac. Process	Material Grade	SMYS	σ_{yhoop} (source)			$\sigma_{ulthoop}$ (source)			σ_{ylong} (source)			$\sigma_{ultlong}$ (source)			σ_y	σ_u
				Unit	Type		Unit	Type		Unit	Type		Unit	Type	[N/mm^2]	[N/mm^2]

LOADING						
Load Type	Loading (source)			Loading Stress Range		No. of Cycles
	Min	Max	Unit	Min	Max	

Table 6.1: Database fields (continued…)

MATERIAL PARAMETERS																
Fracture Parameters									Residual Stresses			FM Parameters				
Charpy	Unit	Temp	CTOD	Unit	J_{IC}	Unit	K_{IC}	Unit	σ_{rhoop}	σ_{rlong}	Failure Mode	A_a	A_b	m_a	m_b	K_{th}

	5							6									
MECHANICAL DAMAGE																	
Type	DENT								GOUGE								
	Shape	d_d	Unit	l_d	Unit	d_d [mm]	l_d [mm]	Location	d_g	Unit	l_g	Unit	d_g [mm]	l_g [mm]	Orientation	Finish	SCF

7											6							
CORROSION											**CRACK**							**COMMENTS**
Corrosion	Length		Width		Depth		L_c	W_c	d_c	Surface	Location	depth (a)		length (2c)		a	2c	
Type		Unit		Unit		Unit	[mm]	[mm]	[mm]	Finish			Unit		Unit	[mm]	[mm]	

Table 6.1: Database fields (…continued)

Notes:	
1	SL1 = Fully acceptable data SL2 = Acceptable data but some nominal values used SL3 = Acceptable data but peculiarities SL4 = Incomplete data, reject
2	M = Mechanical damage (dent and/or gouge) C = Corrosion F = Fatigue crack W = Weld defect O = Other
3	N = Nominal M = Measured C = Calculated U = Unknown
4	SMLS = Seamless SAW = Submerged Arc Welding ERS = Electric Resistance Welding N/A = Not applicable (for FE data)
5	Sq = Square indentor Cyl1 = Cylinder transverse to pipe Cyl2 = Cylinder longitudinal to pipe Sph + Spherical indentor O = Other
6	GW = Girth weld LW = Longitudinal weld P = Parent material
7	G = General I = Internal E = External P = Pit L = Localised

Table 6.2: Database notes

Inspection of Table 6.1 shows that the data has been entered under ten main headings, with sub-headings as follows:

i) Specimen Identification

The 'reference number' and 'author' are the same as in the list of References herein. The 'spec ID' is the specimen identification as used in the source document. The author and spec ID fields are useful in weeding out duplicate sets of data. Each specimen is given a unique 'sequence number' to facilitate trace ability following screening and the creation of data subsets. Where a specimen requires multi-row entries (e.g. for the recording of crack growth data) then letters a, b, c etc. are used after the sequence number to distinguish the row entries. The 'type' column refers to whether the data are test data or finite element (FE) data. The entries under 'screening level' and 'type of defect' are defined in Notes 1 and 2 in Table 6.2 respectively. The latter will be useful for sorting the database and in preparing data subsets.

ii) Pipe Geometry

The sub-headings under this grouping are self-explanatory especially when read in conjunction with Note 3 in Table 6.2. As explained above, the 'source' columns are used for data entry purposes and are hidden following data checking.

iii) Pipe Specification

The three sub-headings under 'pipe specification' record the pipe manufacturing process and the type of material.

iv) Material Properties

Again, these sub-headings are self-explanatory.

v) Loading

The 'load type' identifies the loading regime as appropriate, e.g. pressure, axial, bending, etc. The loading range (or ranges if multi-row entries are being used for crack growth tests) is entered under the 'source' column in the original units. The 'number of cycles' is only relevant for fatigue or crack growth tests, otherwise N/A is entered.

vi) Material Parameters

Sub-headings are provided for brittle fracture parameters, Fracture Mechanics parameters and residual stresses. These parameters might be given in some source documents and will become relevant during appraisals of the various defect assessment methodologies.

vii) Mechanical Damage

The entries under this heading are to characterize the shape, size and location/orientation of dents and gouges. Once again, duplicate columns allow for data entry using source document units and then transposition to a consistent set. The first column under this heading, 'type', allows for subsequent sorting.

viii) Corrosion

The corrosion section allows data pertaining to the nature and extent of any corrosion to be entered. The 'corrosion type' is a qualitative field and is used to define whether the corrosion is internal or external, localized or general, etc.

ix) Crack

The location, depth and length of a crack are entered here.

x) Comments

This section allows the embellishment of any noteworthy aspects gleaned from the source document. It is particularly useful for recording any peculiar testing procedure or observation that is not addressed in other fields.

6.3 Breakdown of Collected Data

Figure 6.1 presents a breakdown of the database by defect type: corrosion defects, mechanical damage defects and girth weld defects. The total number of useful test data-points in the database is 813 as indicated in the top of the figure; 575 corrosion defects, 119 mechanical damage defects and 119 girth weld defects.

As indicated in Figure 6.1, there were 319 corrosion defects and 81 girth-weld defects that could not be assessed because they were either outside the range of applicability of all methods or insufficient information was included with the data to permit assessment. In addition, none of the 119 mechanical damage defects could be assessed because no simplified assessment method is available for mechanical damage defects. This is because internal pressure loading tends to reduce stress concentrations associated with dent-type defects and, therefore, the pipeline capacity may not be reduced by the presence of the dent. The reduction in the capacity in the presence of other types of loading is most commonly assessed using finite element techniques and is beyond the scope of this report.

DATABASE		
813		
Corrosion Defects	Mechanical Damage	Girth Weld Defects
Assessable Data		
575	**119**	**119**
ASME B31G - **218**	None(1)	API 1104 - **38**
DNV F101 - **93**		BS 7910 - **38**
RSTRENG - **251**		R/H/R6 - **38**
Non Assessable Data(2)		
319	**119**	**81**

(1) No standard assessment method is available.
(2) Data entries that were either outside the applicability range of any method, or lacked necessary information for assessment

Figure 6.1: Breakdown of Database

7. PERFORMANCE OF DEFECT ASSESSMENT METHODS

In order to evaluate the performance of the assessment methods described in Section 5, each was applied to the relevant screened data contained in the database. It should be noted in this regard that: -

(a) The range of applicability differs from one assessment method to another.

(b) The required input data differs from one assessment method to another.

For these reasons the data population size available for consideration in the evaluation of each assessment method differs. The numbers assessable by each method are shown in Figure 6.1.

7.1 Girth Weld Defects

Two girth weld defect assessment methods, BS 7910 and R/H/R6, were applied to a common population of thirty-eight data points from the database. In each case, the general Failure Assessment Diagram (FAD) was plotted and the location of the data in relation to the predicted failure surface identified. For the BS 7910 evaluation, a level-2 assessment was conducted. Two different stress intensity factor solutions were used, one for flat plates and the other for curved shells. The results are shown in Figures 7.1 and Figure 7.2, respectively. For the R/H/R6 evaluation, a category-1 assessment was performed and the results are shown in Figure 7.3.

- BS 7910: For the defect population considered, the flat-plate stress intensity factors gave a conservative estimate of the failure surface, with all failure data-points lying well outside the failure surface as shown in Figure 7.1. The curved-shell stress intensity factors, on the other hand, give a more accurate but less conservative estimate of the failure surface, Figure 7.2. In this case, three of the thirty-eight failure data points lie within the failure surface with one right on the surface. The remainders lie comfortably outside the failure surface.

- R/H/R6: For the same defect population, all thirty-eight failure data points fall outside the predicted failure surface as shown in Figure 7.3. Comparison of the method with BS 7910 indicates that, for the data considered, R/H/R6 is slightly more conservative and less accurate than BS 7910 using the flat plate factors, Figure 7.1, since the data lies more distant from the predicted failure surface.

API 1104, 'Welding of Pipelines and Related Facilities', contains acceptance standards for girth-weld defects. These standards are intended for the assessment of weld fabrication defects. Table 7.1 shows the results of applying the API 1104 assessment criteria to the same data points used in the evaluation of BS 7910 and R/H/R6. Column 11 indicates whether the flaw sizes were acceptable while column 12 indicates whether the data-points led to failure of the specimen during the test. The table shows that two defects were classed as 'acceptable' by the API 1104 criteria and indeed these defects did not result in failure during the test. Seven other defects also did not resulting failure although these were classed as 'not-acceptable' by the API 1104 criteria. The results suggest that the API 1104 method is appropriately conservative, for a fabrication standard, in its rejection of girth-weld defects.

Strain	CTOD	a* (mm)	a_{max} (mm)	a/t	a1 (mm)	2c (mm)	D/t	Flaw Depth [mm]	Flaw Length [mm]	Acceptable (Y/N)	
										API 1104	Leggatt
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	5.9	63.5	No	Yes
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	5.5	69.8	No	Yes
0.002	0.03	2.54	5.6	0.5	2.78	44.4	82.3	7.8	68.6	No	No
0.002	0.03	2.54	5.6	0.5	2.78	44.4	82.3	5.4	61.0	No	No
0.002	0.03	2.54	5.6	0.5	2.78	44.4	82.3	10.1	76.5	No	No
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	8.8	81.8	No	No
0.002	0.03	2.54	5.6	0.5	2.78	44.4	82.3	6.4	59.3	No	No
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	9.3	79.0	No	No
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	6.3	63.5	No	Yes
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	6.1	59.6	No	No
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	5.5	64.8	No	Yes
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	5.5	60.3	No	No
0.002	0.10	3.81	5.1	0.5	2.57	41.1	88.9	4.1	300.0	No	Yes
0.002	0.10	3.81	5.1	0.5	2.57	41.1	88.9	3.6	300.0	No	Yes
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	3.3	265.0	No	No
0.002	0.10	3.81	5.6	0.5	2.78	44.4	82.3	3.2	278.0	No	No
0.001	0.10	6.35	5.6	0.5	2.78	44.4	82.3	3.9	279.0	No	No
0.001	0.10	6.35	5.6	0.5	2.78	44.4	82.3	3.7	331.0	No	No
0.001	0.10	6.35	5.6	0.5	2.78	44.4	82.3	3.5	75.0	No	No
0.001	0.10	6.35	7.5	0.5	3.75	60.0	71.1	0.9	14.0	Yes	Yes
0.001	0.10	6.35	7.5	0.5	3.75	60.0	71.1	3.0	38.0	Yes	Yes
0.001	0.10	6.35	7.5	0.5	3.75	60.0	71.1	8.0	70.0	No	Yes
0.001	0.23	7.00	5.6	0.5	2.78	44.4	82.3	3.7	315.0	No	No
0.001	0.10	6.35	5.6	0.5	2.78	44.4	82.3	3.1	282.0	No	No
0.001	0.10	6.35	5.9	0.5	2.93	46.9	78.0	2.9	280.0	No	No
0.001	0.10	6.35	5.9	0.5	2.93	46.9	78.0	3.7	134.0	No	No
0.001	0.10	6.35	5.9	0.5	2.93	46.9	78.0	2.2	116.0	No	No
0.002	0.08	3.81	3.4	0.5	1.69	27.0	90.2	3.1	100.0	No	No
0.002	0.08	3.81	3.4	0.5	1.69	27.0	90.2	2.8	199.0	No	No
0.002	0.08	3.81	3.4	0.5	1.69	27.0	90.2	3.1	51.0	No	No
0.002	0.08	3.81	3.4	0.5	1.69	27.0	90.2	3.9	107.0	No	No
0.001	0.10	6.35	5.9	0.5	2.93	46.8	78.1	2.0	112.0	No	No
0.001	0.10	6.35	5.9	0.5	2.93	46.8	78.1	3.9	141.0	No	No
0.001	0.10	6.35	5.9	0.5	2.93	46.8	78.1	3.5	300.0	No	No
0.001	0.38	7.50	9.5	0.5	4.75	76.0	40.1	4.5	105.2	No	No
0.001	0.46	18.50	9.5	0.5	4.75	76.0	40.1	5.7	139.0	No	No
0.001	0.45	18.50	9.5	0.5	4.75	76.0	40.1	5.0	125.0	No	No
0.001	0.60	25.00	12.7	0.5	6.35	101.6	28.0	10.9	127.0	No	No

Table 7.1: Assessment of API 1104

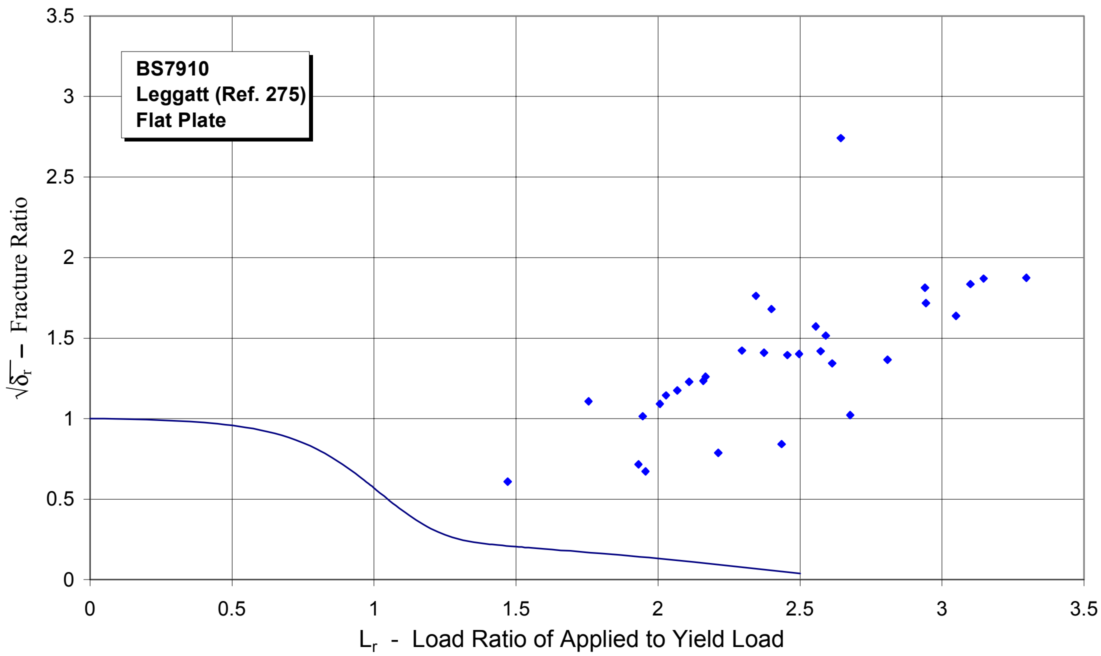

Figure 7.1: Assessment of BS7910 – Level 2 – Flat Plate

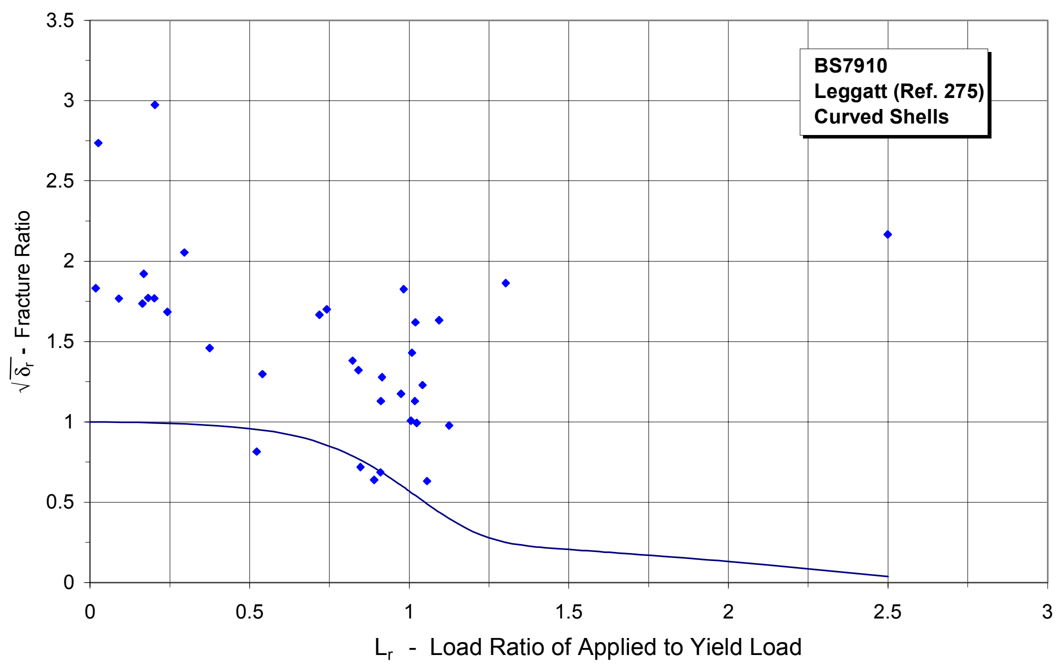

Figure 7.2: Assessment of BS7910 – Level 2 – Curved Shells

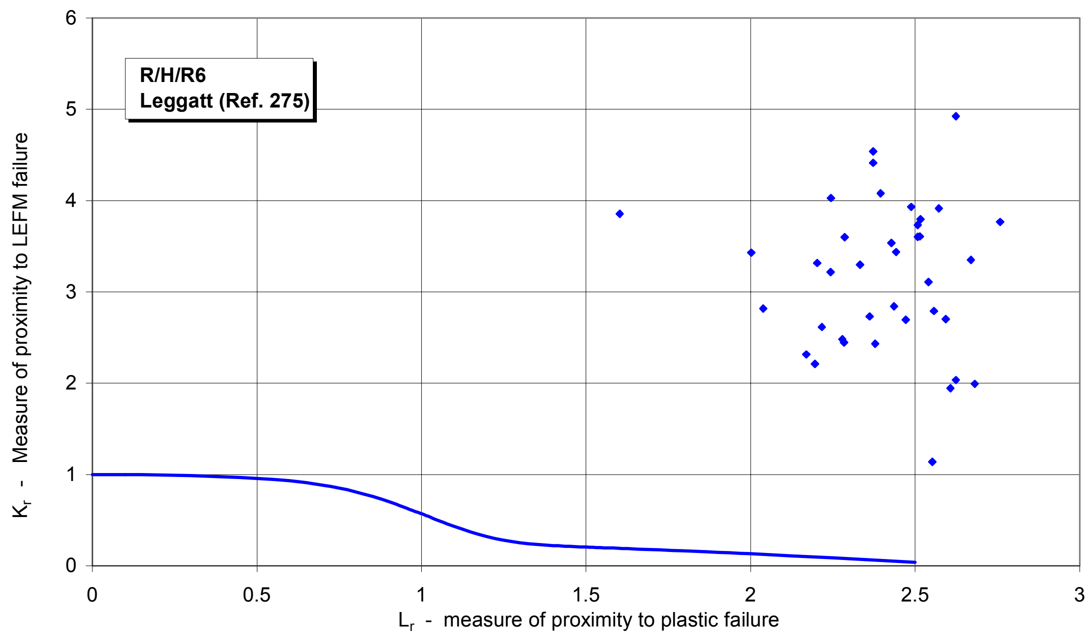

Figure 7.3: Assessment of R/H/R6 – Category 1

7.2 Corrosion Defects

Figures 7.4, 7.5 and 7.6 present the performance of the three corrosion defect assessment methods: ASME BG31, DNV RP-F101 and RSTRENG - 0.85 Area. Due to lack of corrosion profiles included with the test data, the RSTRENG-0.85 Area and Effective Area methods both lead to the same results since in both cases, the corrosion profile is assumed rectangular. The figures present plots of the ratio of measured to predicted burst pressures as a function of the ratio of defect depth to wall thickness. Also indicated on the figure are the statistical mean, standard deviation and coefficient of variation of the data.

The following can be noted:

- As indicated above, the number of points in the three figures is not necessarily the same due to the difference in range of applicability and of required input parameters.

- In general, the RSTRENG software, which is a modified version of ASME BG31, is less conservative than the BG31 method. This is due to the fact that, while the BG31 method uses the maximum corrosion depth, the RSTRENG software uses a profile. Due to lack of corrosion profiles in this study, the rectangular profile was used which appears to assume 0.85 of the corroded depth.

- The DNV RP-F101 appears to be more conservative than the ASME BG31. However, as indicated above, different points are used in both cases, and hence the two plots are not fully consistent.

For consistency, the common set of data points applicable to both the DNV and ASME methods was separated and plotted in Figures 7.7 and 7.8. As indicated by the higher average, the DNV RP-F101 does yield more conservative predictions of burst capacity. However, the lower COV for DNV RP-F101 shows that it is more accurate than ASME BG31.

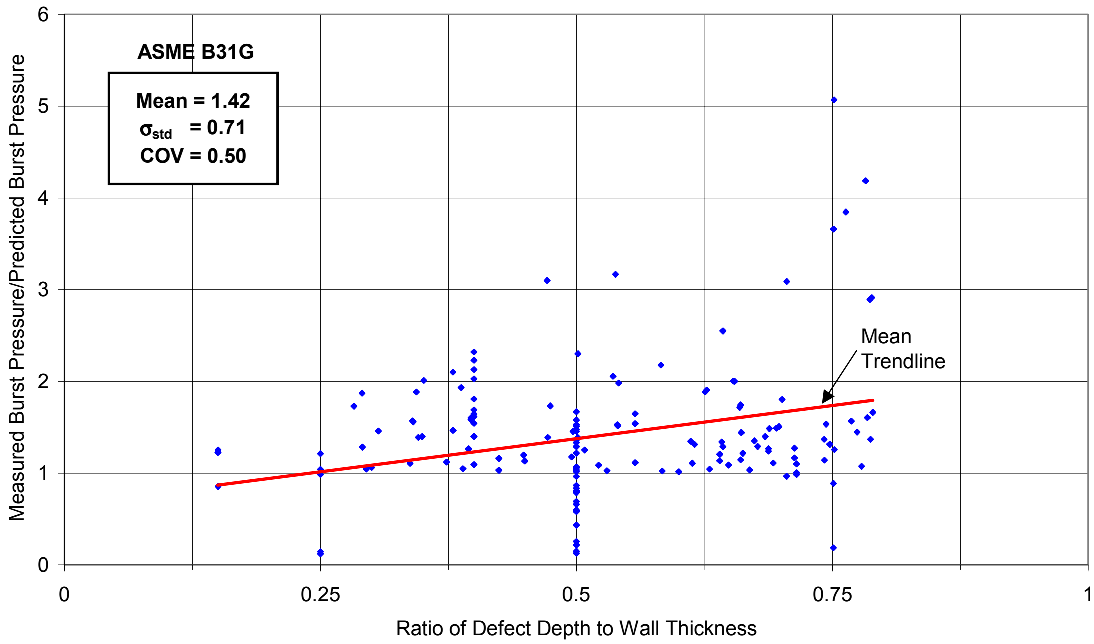

Figure 7.4: Assessment of ASME BG31 Method

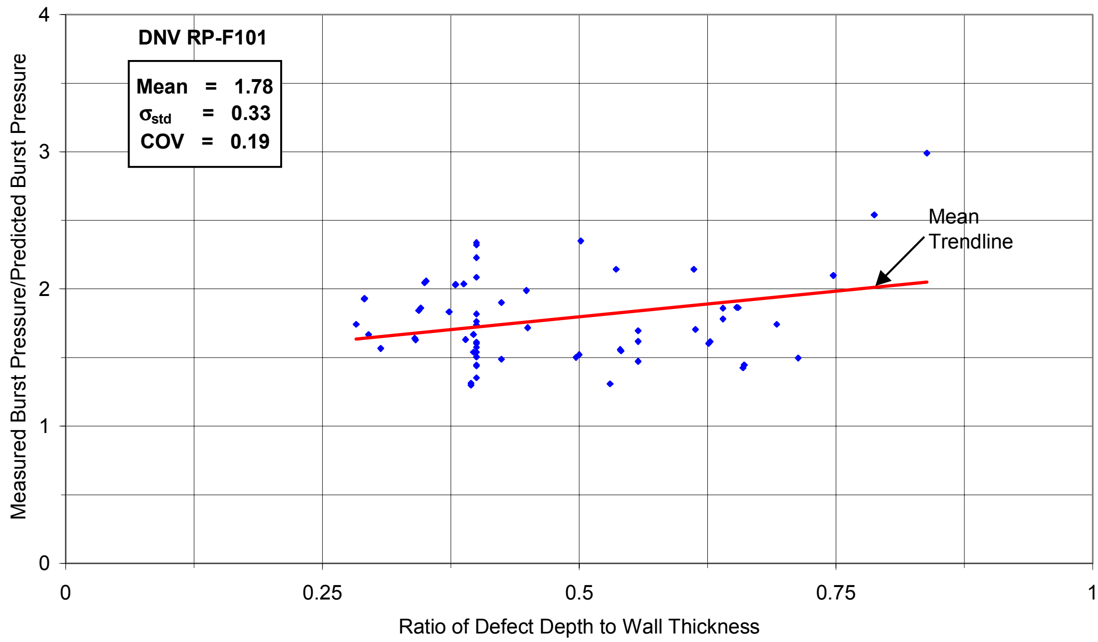

Figure 7.5: Assessment of DNV RP-F101 Method

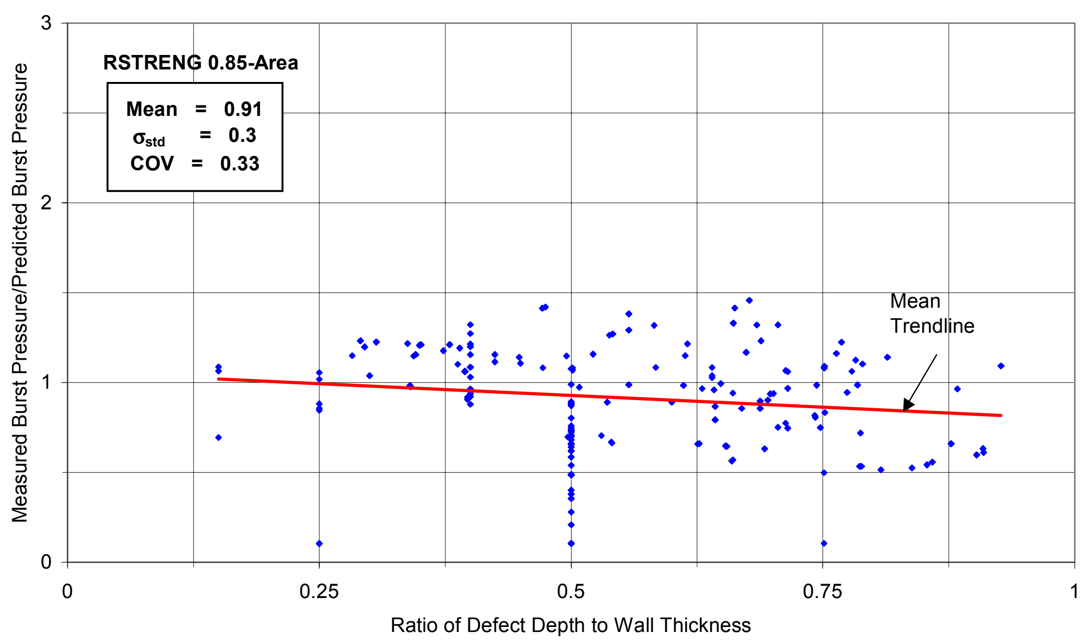

Figure 7.6: Assessment of RSTRENG 0.85-Area Method

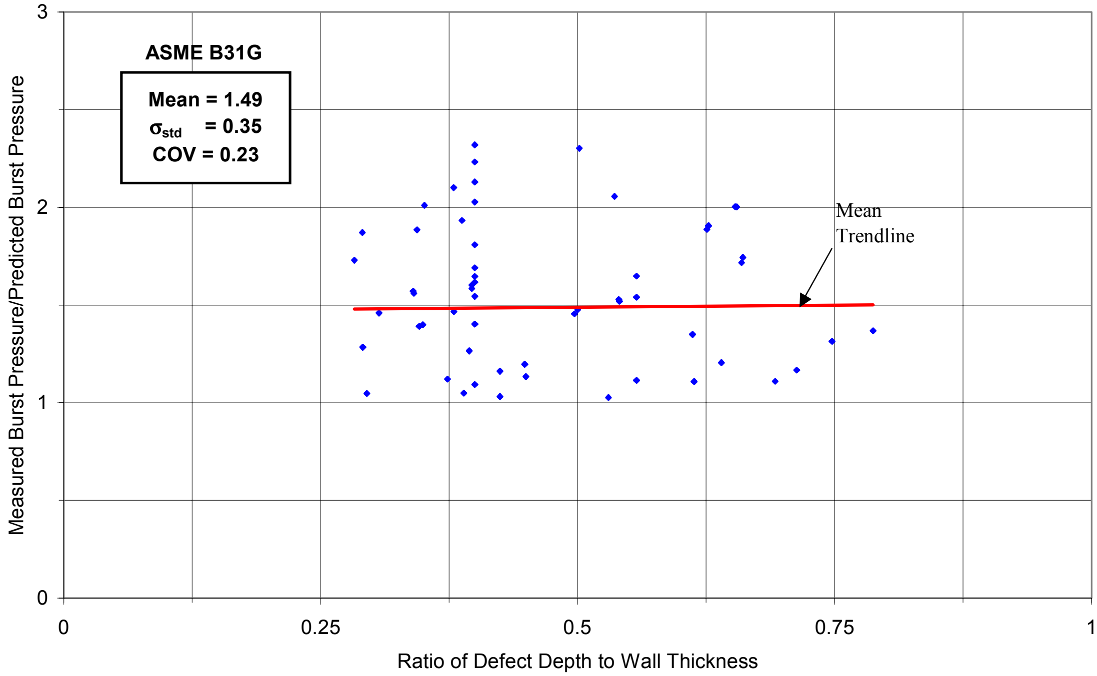

Figure 7.7: Comparison of ASME B31G to common data set

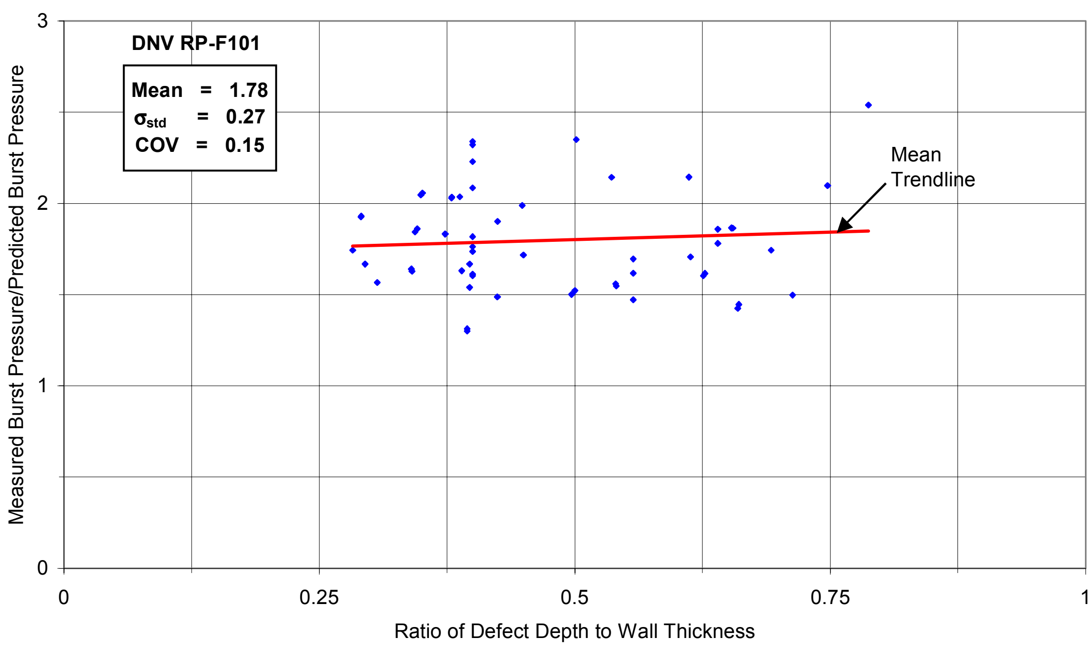

Figure 7.8: Comparison of DNV RP-F101 to common data set

7.3 Mechanical Damage

As indicated in section 5.3, the PRCI's DFGM appears to be a good model for predicting failure due to mechanical damage. The comparison of this method to test data would require the development of finite element numerical models of the dents with due account for material and geometrical non-linearity. This level of assessment is outside the scope of the present study.

7.4 Assessment Guideline

The following conclusions may be drawn based on the evaluation of assessment methods presented in this section. These conclusions should not necessarily be considered as generic but rather as specific to the data considered in this study.

Girth Weld Defects

- API 1104 offers a simple and appropriately conservative method for assessment of defects during fabrication.
- R/H/R6 Category 1 appears to be slightly more conservative than BS 7910 Level 2 with flat plate stress intensity factors.
- In BS 7910, the curved shell stress intensity factors appear to be less conservative than the flat plate factors.

Corrosion Defects

- DNV RP-F101 appears to be more conservative than ASME BG31, although gives a better fit to data (lower COV).
- The RSTRENG software, which is based on a modified version of the ASME BG31, appears to be the least conservative.

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141	Assessment of Long Corrosion Grooves in Line Pipe	Duane S. Cronin	06/09/1996	First International Pipeline Conference 1996
142	Pipeline Failure Investigations: Analytical Techniques and Case Studies	Brian R. Wilson	06/09/1996	First International Pipeline Conference 1996
143	Life After Inspection	Keith Grimes	06/09/1996	First International Pipeline Conference 1996
144	The Evaluation and Restoration of a Deteriorated Buried Gas Pipeline	Ricardo Dovico	06/09/1996	First International Pipeline Conference 1996
145	AC Corrosion: A New Threat to Pipeline Integrity?	Robert A. Gummow	06/09/1996	First International Pipeline Conference 1996
146	Evaluation of Stray Current Effect on the Cathodic Protection of Underground Pipeline	K. W. Park	06/09/1996	First International Pipeline Conference 1996
147	Coating Integrity Survey Using DC Voltage Gradient Technique at Korea Gas Corporation	Y. B. Cho	06/09/1996	First International Pipeline Conference 1996

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148	Corrosion and Cathodic Protection at Disbonded Coatings	J. H. Payer	06/09/1996	First International Pipeline Conference 1996
149	Stress and Strain State of a Gas Pipeline in Conditions of stress-Corrosion	V. V. Kharionovsky	06/09/1996	First International Pipeline Conference 1996
150	Pipeline SCC in Near-Neutral pH Environment: Recent Progress	W. Zheng	06/09/1996	First International Pipeline Conference 1996
151	Stress Corrosion Cracking of a Liquid Transmission Line	Ravi M. Krishnamurthy	06/09/1996	First International Pipeline Conference 1996
152	Factors Influencing Stress Corrosion Cracking of Gas Transmission Pipelines: Detailed Studies Following a Pipeline Failure: Part 1, Environmental Considerations	Martyn J. wilmott	06/09/1996	First International Pipeline Conference 1996
153	Hydrogen-Induced Stress Corrosion Cracking of Pipe Lines of Russia	Tatyana K. Sergeyeva	06/09/1996	First International Pipeline Conference 1996
154	Investigation of the Passivity, Hydrogen Embrittlement and Threshold Stress of Duplex Stainless Steel	Mirko Gojic	06/09/1996	First International Pipeline Conference 1996
155	Study of Stress-Corrosion Cracks: Physical and Mechanical Properties of Steel After Hydrostatic Re-Testing	S. Karpov	06/09/1996	First International Pipeline Conference 1996
156	Mechanisms of High-pH and Near-Neutral-pH SCC of Underground Pipelines	John A. Beavers	06/09/1996	First International Pipeline Conference 1996
157	Stress Corrosion Crack Growth of Pipeline Steels in NS4 Solution	A. Plumtree	06/09/1996	First International Pipeline Conference 1996
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159	The Development of the Pipe Safe Risk Assessment Package for Gas Transmission Pipelines	Michael R. Acton	06/07/1998	International Pipeline Conference 1998
160	Risk Management at TransCanada Pipelines	Kevin Cicansky	06/07/1998	International Pipeline Conference 1998
161	Relative Risk Assessment - The Competitive Advantage	Bruce D. Beighle	06/07/1998	International Pipeline Conference 1998
162	Risk Assessment of Gas Transmission Pipelines in Mexico	Jose L. Martinez	06/07/1998	International Pipeline Conference 1998
163	Safe Separation Distances: Natural Gas Transmission Pipeline Incidents	Eugene Golub	06/07/1998	International Pipeline Conference 1998
164	Progress of the US Department of Transportation Risk Management as a Regulatory Alternative	Keith G. Lewis	06/07/1998	International Pipeline Conference 1998
165	Geologic Hazards Reconnaissance and Mitigation, and Implications to Natural Gas Pipeline Operations and Risk Management	Jill Braun	06/07/1998	International Pipeline Conference 1998
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181	Floating-Roof Tank Heel Reduction Options and Heel Turnover Emissions	Terry A. Gallagher	06/07/1998	International Pipeline Conference 1998
182	Maintenance Plan for 1956 Vintage Storage Tank Facility	Brian S. Buck	06/07/1998	International Pipeline Conference 1998
183	Can Advanced Repair and Maintenance Technologies Prevent Machines From Failing	James R. Mugford	06/07/1998	International Pipeline Conference 1998

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185	Application of the Quartz Crystal Microbalance to Corrosion Investigation	Heijan Sun	06/07/1998	International Pipeline Conference 1998
186	Inhibitor Selection for Internal corrosion Control of Pipelines	S. Papavinasam	06/07/1998	International Pipeline Conference 1998
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191	Fatigue Damage Calculations for a Dented and Ovalled Section of the TransAlaska Pipeline System at Thompson Pass	James D. Hart	06/07/1998	International Pipeline Conference 1998
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193	TransAlaska Pipeline System Linewide Slackline Investigations for Potential Pipe Vibrations	W. G. Tonkins	06/07/1998	International Pipeline Conference 1998
194	Fatigue Behavior of Line Pipes Subjected to Severe Mechanical Damage	Naoto Hagiwara	06/07/1998	International Pipeline Conference 1998
195	Investigations of Dent Rerounding Behavior	Michael J. Rosenfeld	06/07/1998	International Pipeline Conference 1998
196	Non-Destructive Techniques for Measurement and Assessment of Corrosion Damage on Pipelines	Richard Kania	06/07/1998	International Pipeline Conference 1998
197	Estimation of Measurement Errors	Arti Bhatia	06/07/1998	International Pipeline Conference 1998
198	EMAT Generation of Horizontally Polarized Guided Shear Waves for Ultrasonic Pipe Inspection	Julie Gauthier	06/07/1998	International Pipeline Conference 1998
199	An Automated ACFM Peak Detection Algorithm With Potential for Locating SCC Clusters on Transmission Pipelines	L. Blair Carroll	06/07/1998	International Pipeline Conference 1998
200	High-Temperature, High-Pressure Rotating Electrode System	S. Papavinasam	06/07/1998	International Pipeline Conference 1998
201	Mechanical Development of a NPS 36 Speed Controlled Pipeline Corrosion Measurement Tool	Robert S. Evenson	06/07/1998	International Pipeline Conference 1998
202	TCPL In-Line Inspection Management Program	Patrick H. Vieth	06/07/1998	International Pipeline Conference 1998
203	The Operational Experience and Advantages of Using Speed Control Technology for Internal Inspection	Reena Sahney	06/07/1998	International Pipeline Conference 1998
204	NPS 8 Geopig: Inertial Measurement and Mechanical Caliper Technology	Phil Michailides	06/07/1998	International Pipeline Conference 1998
205	The Changing Role of Inspection	Keith Grimes	06/07/1998	International Pipeline Conference 1998
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211	A Review of the Concept of Mildly Sour Environments	Richard J. Pargeter	06/07/1998	International Pipeline Conference 1998
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221	Full-Scale Wrinkling Tests and Analyses of Large Diameter Corroded Pipes	Marina Q. Smith	06/07/1998	International Pipeline Conference 1998
222	Correction for Longitudinal Stress in the Assessment of Corroded Line Pipe	K. Andrew Roberts	06/07/1998	International Pipeline Conference 1998
223	A New Rupture Prediction Model for Corroded Pipelines Under Combined Loadings	Wei Wang	06/07/1998	International Pipeline Conference 1998
224	The Use of Reliability Based Limit State Methods in Uprating High Pressure Pipelines	Andrew Francis	06/07/1998	International Pipeline Conference 1998
225	Pipeline Repair Based on Diagnostic Inspection - Investment Return	Barnabas Pallaghy	06/07/1998	International Pipeline Conference 1998
226	The Canadian Energy Pipeline Association Stress Corrosion Cracking Database	Bruce R. Dupuis	06/07/1998	International Pipeline Conference 1998
227	Use of the Elastic Wave Tool to Located Cracks Along the DSAW Seam Welds in a 32-inch (812.8-mm) OD Products Pipeline	Willard A. Maxey	06/07/1998	International Pipeline Conference 1998
228	In-Line Inspection Tools for Crack detection in Gas and Liquid Pipelines	H. H. Willems	06/07/1998	International Pipeline Conference 1998
229	Comparison Between In-Line Crack Detection and Hydrostatic Testing in IPL's Line 3	Michael A. Gardiner	06/07/1998	International Pipeline Conference 1998
230	Application of Material Standards & ISO Quality Management Systems	Keith E. W. Coulson	06/07/1998	International Pipeline Conference 1998
231	The Australian Petroleum Pipeline Code AS 2885 - 1997	Ken J. Bilston	06/07/1998	International Pipeline Conference 1998
232	Reliability of Mechanised UT Systems to Inspect Girth Welds During Pipeline Construction	Jan A. de Raad	06/07/1998	International Pipeline Conference 1998
233	Customized Ultrasonic Systems for Gas Pipeline Girth Weld Inspections	Michael D. C. Moles	06/07/1998	International Pipeline Conference 1998
234	Three Layer Epoxy/Polyethylene Side Extruded Coatings for Pipe for High Temperature Application	Mike Alexander	06/07/1998	International Pipeline Conference 1998
235	Deformation and Fracture Behaviors of Polyethylene Coatings on the Natural Gas Transmission Line With Ultraviolet Exposure	Seong-Min Lee	06/07/1998	International Pipeline Conference 1998
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237	Development of Heavy Gauge X80 Linepipe	M. Milos Kostic	06/07/1998	International Pipeline Conference 1998
238	An Investigation of the Factors Influencing the Formation of Hollow Bead Bores in Pipeline Girth Welds	Gersende M. Delphine Cantin	06/07/1998	International Pipeline Conference 1998
239	Quality and Productivity Improvements in the Field Welding of High Strength Thin Walled Pipelines	Frank J. Barbaro	06/07/1998	International Pipeline Conference 1998
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242	Material Assessment of Canadian Saw Line-Pipes	D. K. Mak	06/07/1998	International Pipeline Conference 1998
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259	Inspection Technologies for a Wide Range of Pipeline Defects	Keith Grimes	33651	Pipeline Pigging and Inspection Technology Conference
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261	Use of In-Line Inspection Data for Integrity Management	Patrick H. Vieth	06/21/1905	Corrosion 99
262	Which Smart Pig do I Choose ? A Comparison of Magnetic Flux Technologies from an Operator's Viewpoint	Ken Plaizier	06/05/1993	
263	In-Line Inspection Technologies for Mechanical Damage and SCC in Pipeline- Final Report on Task 1 and 2	T.A. Bubenik	12/01/1998	
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266	Evaluating the Remaining Strength of Corroded Pipelines	Chouchaoui B A.	1993	Ontario
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268	A Three Level Assessment of the Residual Strength of Corroded Line Pipe	Chouchaoui B A.	1994	13th Offshore Mechanics and Arctic Engineering Conference, Houston
269	Criteria for Dent Acceptability in Offshore Pipeline	Fowler J R.	1993	25th Offshore Technology Conference
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271	The Development of Fitness for Purpose Flaw Acceptance Criteria for Sleeve Connections	Gordon J R.	1993	8th Annual Symposium on Line Pipe Research
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323	Pigging of Subsea Pipelines	Schaefer, E F	1991	23rd Offshore Technology Conference
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333	New International Standards for Offshore Pipelines	Herman Moshagen, Erling gjertvert	06/20/2005	Internatinal offshore and Polar engineering Conference
334	Design Through Analysis Applying Limit-State Concepts and Reliability Method	Yong Bai and Per Damsleth	05/24/1998	Internatinal offshore and Polar engineering Conference
335	Experience from Operation, Inspection and Monitoring of Offshore Pipeline System on the Norwegian Continental Shelf	Ase Katrine Thomsen	05/24/1998	Internatinal offshore and Polar engineering Conference
336	Realtime Monitoring to Detect Third-Party Damage	B.N. Leis, R.B. Francini	05/24/1998	Internatinal offshore and Polar engineering Conference
337	Direct Electrical heating of Pipelines as a Method of Preventing Hydrate and Wax Plugs	Jens Kristian Lervik	05/24/1998	Internatinal offshore and Polar engineering Conference
338	Pressure-Displacement Behavior of Transmission Pipelines under Outside Forces--Towards a Services Criterion for Mechanical damage	B.N. Leis, R.B. Francini	05/24/1998	Internatinal offshore and Polar engineering Conference
339	Assessment of Free Spanning Pipelines Using the DnV guideline	Olav Fyrileiv and Kim Mork	05/24/1998	Internatinal offshore and Polar engineering Conference
340	Plastic Failure of Pipelines	Michelle S. Hoo Fatt	05/24/1998	Internatinal offshore and Polar engineering Conference
341	Plastic Deformation and Local Buckling of Pipelines Loaded by Bending and Torsion	A. M. Gresnigt	05/24/1998	Internatinal offshore and Polar engineering Conference
342	The effect of Tension-Fractured and Compression-Crushed Zones on Pipe Uplift Resistance in Frozen Soil	A. Foriero	05/24/1998	Internatinal offshore and Polar engineering Conference
343	Analytical Collapse Capacity of Corroded Pipes	Yong Bai and Soren Hauch	05/24/1998	Internatinal offshore and Polar engineering Conference
344	Pipeline Design Strategies for Deep Water	Andrew palmer	03/22/1999	Deepwater Pipeline Technology Conference
345	Strength Design of Deepwater Pipelines	Yong Bai, Per Damsleth	03/22/1999	Deepwater Pipeline Technology Conference
346	Integrity Assessment of Deep Water Pipelines	Majid Al Sharif	03/22/1999	Deepwater Pipeline Technology Conference
347	External Corrosion Control and Corrosion Inspection of deepwater Pipelines	Jim Britton	03/22/1999	Deepwater Pipeline Technology Conference
348	The Effect of Plastic Deformation on the Fatigue Performance of Steel Catenary Risers	Elie Kodaissi	03/22/1999	Deepwater Pipeline Technology Conference
349	Complexities of Fatigue Analysis for Deepwater Riser	Mike Campbell	03/22/1999	Deepwater Pipeline Technology Conference
350	Development of Fatigue and Inspection Criteria for Steel Catenary Risers	Robert Carnes,	03/22/1999	Deepwater Pipeline Technology Conference
351	Limitations of Fitness for Purpose Assessments of Pipeline Girth Welds	Roodbergen, A H	1987	International Conference on Pipe Technology,Rome 1987
352	Integrity Assessment of Offshore Pipelines by Use of Intelligent Inspection Tools	M. Beller and W. Garrow		12th International Conference on Offshore Mechanics and Arctic Engineering
353	A Decade of Inspection Findings Compared with Design Aspects of Two North Sea Pipelines	Michael A. Krogh		12th International Conference on Offshore Mechanics and Arctic Engineering
354	Testing of Susceptibility to Environmentally Assisted Cracking (EAC) in H_2S Environment	John D. Edwards		12th International Conference on Offshore Mechanics and Arctic Engineering
355	Sour Resistant X65 UOE Line Pipe for Low-Temperature Service	Y. Terada	05/25/1997	7th International Offshore and Polar Engineering Conference
356	Non-Linear Finite Element Prediction of Wrinkling in Corroded Pipe	Daniel P. Nocolella	05/25/1997	7th International Offshore and Polar Engineering Conference
357	Limit-State Design of High-Temperature Pipelines	Frans J. Klever	1994	13th Offshore Mechanics and Arctic Engineering Conference, Houston
358	Wall Thickness Design for High Pressure Offshore Gas Pipelines	Richard Verley	1994	13th Offshore Mechanics and Arctic Engineering Conference, Houston
359	Submarine Pipeline Inspection: The 12 Years Experience of Transmet and Future Developments	Luigi Iovenitti	1994	13th Offshore Mechanics and Arctic Engineering Conference, Houston
360	TMCP - Application for Production of High Strength, High Toughness Line Pipe Steels	A. Streibelberger	1991	10th Offshore Mechanics and Arctic Engineering Conference
361	Development and Mass Production of X80 Line Pipe	Shigeru Endo	1991	10th Offshore Mechanics and Arctic Engineering Conference
362	Sour Service Large-Diameter Line Pipe Having Good Field Weldability and Sulphide Stress Corrosion Cracking Resistance	H. Tamehiro	1991	10th Offshore Mechanics and Arctic Engineering Conference
363	Future Needs for Integrity Evaluation	Andrew Palmer	12/04/1991	International Workshop on Offshore Pipeline Safety
364	Design and Installation issues for integrity	Dave McKeehan	12/04/1991	International Workshop on Offshore Pipeline Safety
365	Evaluation of Integrity, Reliability Assessment	Tom Zimmerman	12/04/1991	International Workshop on Offshore Pipeline Safety
366	Appendix A - Inspection Considerations	D. W. Barry	12/04/1991	International Workshop on Offshore Pipeline Safety

No.	Title	Author	Date	Conference
367	Corrosion Control Survey Methods for Offshore Pipelines	Clark Weldon	12/04/1991	International Workshop on Offshore Pipeline Safety
368	Recent Developments in Pipeline Integrity Technology	Tom Bubenik	12/04/1991	International Workshop on Offshore Pipeline Safety
369	Effects of Stress Ratio on Fatigue Crack Growth Rates in X70 Pipeline Steel in Air and Saltwater	Vosikovsky, O	1980	Journal of Testing and Evaluation,vol 8, no2, March,80, pp. 68-73
370	An Analysis of Crack Extension by Corrosion Fatigue in a Crude Oil Pipeline	Vosikovsky, O	1978	International Journal of Pressure Vessels and Piping
371	Comparison of API and CSA Offshore Pipeline Stress and Strain Design Criteria	Ray J. Smith	1999	Alaska Arctic Pipeline Workshop
372	Pipeline Out of Straightness and Depth of Burial Measurement Using an Inertial Geometry Intellegent PIG	Stein Wendel	1999	Alaska Arctic Pipeline Workshop
373	RAM Pipe Requal: A risk Assessment & Management Based Process for the Requalification of Marine Pipeline	R.G. Bea	1999	Alaska Arctic Pipeline Workshop
374	Can Limit States Design be used to Design a Pipeline Above 80% SMYS	T.J.E. Zimmerman	1998	17th International Concerence on Offshore Mechanics and Arctic Engineering
375	Reliability, Corrosion, & Burst Pressure Capacities of Pipelines	Robert G. Bea	2000	19th International Conference on Offshore Mechanics and Arctic Engineering
376	Reliability based Criteria for Measures to Corrosion	Norio Yamamoto	1998	17th International Concerence on Offshore Mechanics and Arctic Engineering
377	Assessment of the Intergrity of Structure Containing Defects R/H/R6 Revision 3	I. Milne, R. Ainsworth	1997	
378	Corroded Pipeline Recommended Practice RP-F101	Det Norske Veritas	1999	
379	Design, Construction, Operation, and Maintenance of Ofshore Hydrocarbon Pipelines (Limit State Design)	API	Jul-99	
380	Intelligent Pigging of the Ekofisk Subsea Pipeline Network	Nummedal, T.A.	1991	Offshore Technology Conference
	SCC - Stress corrosion cracking			

APPENDIX A: NOTES OF MEETINGS WITH OPERATORS

INTERVIEW: Operator No. 1

Operator No. 1 owns a number of pipelines in the North Sea. Most of the pipelines are large diameter (up to 42 inch) high-pressure gas lines; the oil lines tend to be short in-field (e.g. subsea wellhead to platform) flow lines of small diameter.

The interviewee stated that very few problems had been experienced with the pipelines. This good operational history may be due to at least three factors that were discussed during the course of the interview:

- The gas is generally sweet and is carefully dried before it is conveyed.
- The pipeline systems are not old, typically being less than 15 years.
- Meticulous procedures are used for steel, pipe and pipeline manufacture as discussed below.

Problems during the manufacturing stage are relatively easily identified and corrected. In-service anomalies would appear to be confined to a few instances of internal corrosion at the 6 o'clock position due to dampness caused by process irregularities, the corrosion being within the first km from the platform.

Interestingly, this Operator has its own specifications for steel grades. The preferred strength is 450MPa and in this respect it is equivalent to API X65. However the Operator's specification has stricter requirements on steel chemistry and geometric tolerances than the API specifications. The improved weldability of the steel leads to fewer defects during pipe/pipeline manufacture and also to fast production rates (e.g. a 42″ dia. x 30mm pipeline could be produced at a rate of 4.5km/day from a lay barge). The Operator is involved in steel production to ensure compliance with its specification.

The steel plate is rolled and welded to form 12.2m (40′) lengths. Ultrasonic inspection is used on the longitudinal weld and the ends are x-rayed over a 300mm length. At this stage welds rarely present problems; defects tend to consist of mechanical surface damage (i.e. minor dents, scratches). Any scratch is removed by grinding and the area examined by MPI or dye penetrant methods. The remaining wall thickness is checked using ultrasonics. The pipe lengths may then be subjected to a pressure test. The internal surface is grit blasted, visually inspected for defects, painted and then inspected again for continuity of the paint coating. (The paint coating is applied to improve gas flow only, and not for corrosion protection. It was claimed that flow rates are improved by 5 to 10%.) The external surface is also grit blasted, inspected and either a 6mm asphalt or a 3mm three-layer system (fusion bonded epoxy/glue/poly-propolyne) is applied. A 40 to 100mm thick reinforced concrete coating is used for protection against mechanical damage and for weighting purposes.

The prepared pipe lengths are stored around the coating yard until required. At that time they are washed internally and subjected to a visual inspection to check for any damage incurred during storage.

On the lay barge, the SAW welding process is used at the double jointing station to produce 24.4m pipe lengths. The double jointed pipes are then transferred to the main line which consists of several MIG welding stations, the first laying the root pass and the last the capping runs. After these stations comes the NDT, repair and field coating stations. The pipeline then travels down the stinger. Usually, only spot checks are carried out between the MIG stations. However, for one project involving a duplex stainless steel line, a full inspection using ultrasonics (TOF) was conducted after only two weld beads had been laid. At the NDT station, x-ray inspection techniques have tended to be used. This will size the length of any defect but not the depth. The Operator therefore assumes a depth equivalent to the height of two weld beads when comparing the defect against normal workmanship criteria. More recently, AUT (automatic ultrasonic testing) has been used at the NDT station which can size length and depth. An Engineering Critical Assessment is used to set acceptable defect size.

Whenever possible, the Operator prefers to let the pipeline lie on the seabed. But where uneven topography could leave unacceptable free spans or where fishing activity is likely, trenching or rock dumping is employed. A survey vessel aft of the lay barge conducts a visual inspection of the pipeline by ROV.

After pipeline completion, a hydrostatic pressure test is conducted, followed by cleaning with pigs and drying. The Operator would like to dispense with the pressure test as it is time-consuming and expensive. It was also noted that longitudinal welds are more critical than girth welds as hoop stresses are generally higher than longitudinal stresses, and that all longitudinal welds are pressure tested at the mill.

In-service inspection has relied on British Gas' smart pigs using MFL (magnetic flux leakage) techniques. The good inspection history of the gas lines has allowed a relaxation of inspection intervals. Indeed, the only incidences of defects are the corrosion patches near the platform mentioned above. Defect assessment has been based on PD 6493 and, more recently, BS 7910. Preliminary assessment would be based on the 'RSTRING' package.

It was concluded that the care exercised in steel, pipe and pipeline manufacture, coupled with sweet gas conditions, has led to the good operational record for the Operator's pipelines.

INTERVIEW: Operator No. 2

Operator No. 2 is responsible for pipelines across all sectors of the UK continental shelf. Those in the southern North Sea are likely to be gas lines, elsewhere they tend to convey multi-phase products. The Operator classifies the pipelines into the following three categories, although it was recognized that there may be overlap amongst the categories:

1) In-field lines

   These tend to be short (i.e. less than 1.5km) and of small diameter (i.e. typically 6″ to 8″). They carry unprocessed fluids at pressures up to 200 bar in normal operating conditions but pressures approaching 800 bar can arise when High Pressure wells are shut in, generally over short lengths (say up to 100m).

2) Inter-field lines

   These are of intermediate lengths (i.e. up to about 25km) and diameters (typically around 12"). Maximum pressures are about 200 bar. Fluids can be processed or unprocessed.

3) Trunk lines

   These can be long (100km plus) and are of large diameter. Operating pressures are generally in the range of 100 to 200 bar. The fluids are processed.

Good operational history has been experienced with all pipelines. Lines are subject to hydro-testing followed by external and internal inspections at periodic intervals. For external inspections, a towed vehicle housing side scan sonar equipment is used to look for scour, pipe spanning, burial due to slip, evidence of fishing activity (e.g. by tracks) or lateral movement of the pipe. If evidence of disturbance is found, an ROV camera may be deployed to investigate further.

For internal inspections, pigs are used. Generally, the in-field lines can not be pigged due to a lack of arrangements to launch and catch pigs and because of the small diameter of the lines. Inter-field lines can be pigged if they are looped; if they are single lines then sometimes arrangements are made for a ROV-installed temporary pig launcher/trap. Other possibilities were discussed for pigging single lines including crawler pigs with umbilicals (with ultrasonic equipment or camera mounted on the crawler), and contra-flow pigs using the flow for motive power (akin to sailing against the wind). Although bi-directional cleaning pigs exist, the interviewee was not aware of any bi-directional smart pigs. Trunk lines can generally be pigged.

The UK pipeline safety regulations have, over the last three years, prompted a change to a risk-based approach in defining inspection plans; inspection intervals greater than one year are now common. It was stated that the regulations assign responsibility for a pipeline to the operator who actually controls the valves. For certain inter-field lines running between installations (platform, subsea manifolds, etc.) owned by different operators, the pipeline owner may not, in fact, be the operator who controls the valves. This is a slightly unsatisfactory state of affairs as the owner, after all, decides what will flow through the line, and has made the investment in the line that he will want to protect (by integrity management).

The Operator uses 2nd generation smart pigs where other inspection data indicates better information is required. Instrumentation that can be included in cleaning pigs was discussed. This is a relatively new development that should provide cheaper/lower risk alternatives to full scale smart pigging, though it is not currently in common use and certainly not by the operator. In some respects, the use of large smart pigs presents additional risks, most notably in the possibility of the pig getting stuck in the pipeline. Cost was also another factor cited as a disadvantage.

Local corrosion rates are measured in line by corrosion coupons and corrosion probes. Corrosion coupons are sacrificial elements, held into the pipe wall by special housings, and removed at intervals to measure weight loss. Corrosion probes indicate corrosion rates by a change in electrical resistance.

It was believed that the internal and external inspections are generally sufficient to allow the state of the pipeline to be inferred.

For defect assessment the Operator uses in-house procedures. These are based on ASME B31G but with modifications to make the requirements less conservative but still remaining robust.

INTERVIEW: Operator No. 3

This Operator owns almost 1000 miles of sub sea hydrocarbon pipelines in the waters of the Gulf of Mexico. The Pipeline Department of the company is responsible for the pipeline from the export riser to the beach; the Production Department of the company operates the flow-lines and local jumpers from the wells to the platform. The hydrocarbon inventory is about 20% gas and about 80% crude oil. The gas is generally fairly sweet and dry and requires minimal offshore processing. The pipelines range in size from 6 inches to 20 inches.

The company uses API 5L as the standard for line-pipe specification, however, more rigorous inspection requirements are stipulated by the company for pipe with longitudinal seam welds, including 100% UT. This is reflective of in-service experience and a lack of faith in the ability of inspection systems to reliably detect weld defects. Materials from Gr. B to X60 are typical and the operator had no experience of defect issues pertaining to high strength steels.

Routine inspections are not implemented for the pipeline system although the company estimates that approximately 80% of the pipelines (from the export riser to the beach) are piggable. A deterministic risk assessment technique is used to rank the pipelines by potential to fail and by consequence of failure. The risk assessment is based on field experience and is repeated every few years or as operational conditions change.

Inspections, when performed, are seeking mainly corrosion defects, which are the most prevalent based on operational experience. The company does have some experience with MFL Smart Pigs in the Gulf of Mexico, deployed for purposes of corrosion defect detection. Dents cannot generally be detected by the systems that have been employed to date, unless the tool is physically impeded. The Pigs used by the company do not differentiate between internal and external defects; however, in the experience of the company this is often discernable from the nature and, in particular, the location of the defect.

The company does not perform external pipeline inspections in the Gulf of Mexico due to the low visibility and the fact that the pipelines are generally buried.

The major cause of loss of pipeline integrity, resulting in loss of inventory, was stated to be third party interference. This included general shipping and, in particular, the influence of vessels/barges experiencing mooring failures during hurricanes and dragging anchors through pipelines.

Of other potential pipeline defects, the operator advised that corrosion was the most significant. The company reported that their crude oil lines, where the consequence of loss of inventory was greatest, were more susceptible (than the gas lines) to corrosion defects. The reasons for the increased propensity for internal corrosion were cited as higher water content, periods of low flow rate, inadequate or insufficient inhibitors and/or insufficient pigging (cleaning).

The philosophy of the company with regard to defect assessment was to apply the recommendations of ASME/ANSI B31G to detected corrosion defects. For defects failing the acceptance criteria contained in the code the company policy was to either repair/replace the line segment or to closely monitor for leaks. It was felt that the codified assessment criteria were conservative; but that the code was a tool representing operational field experience and that recourse to more sophisticated assessment was not cost effective due to the requirement for greater inspection reliability/accuracy.

INTERVIEW: Operator No. 4

The Company operates a variety of sub sea pipelines ranging in size from 4" to 36". These pipelines range in service from liquids to gas to multiphase.

Typically, internal smart pig inspections are not routinely implemented for pipeline systems in the Gulf of Mexico and the majority of existing lines were not originally designed or built to accommodate smart tool pigs. The retrofitting of lines to accept smart pigs may be accomplished in some cases, if desired by the operator, however for very many cases it is not possible to retrofit for smart pigging and maintain essential configurations of these systems (configurations for example such as subsea tie-ins or branch connections). Issues affecting smart pigging often center around the prevention of the tool becoming stuck in a pipeline and many critical factors must be considered such as tee fittings for branching pipelines, changing line wall thickness, different line sizes, riser size and configuration, existence of pig traps, size of pig traps, and topsides facilities piping etc. The consequential loss of production, potentially from multiple facilities, and cost to locate and retrieve a stuck tool from a sub sea line in such an event, is a significant commercial risk.

An emerging technology that has been proposed and performed by one inspection tool service provider is the use of wire-line techniques for deployment and retrieval of specialized inspection tools. This involves shutting the system down temporarily but may enable inspection of a riser and some distance of pipeline (reportedly up to a mile from the platform) that is not otherwise feasible.

Various monitoring techniques are used to mitigate environmental and commercial risks associated with potential leaks. These may include monitoring pressure drop and/or quantity balances or automated tracking of trends and alarm signals to alert for discrepancies. Helicopter fly-over is used to inspect integrity along pipeline routes or to assist in location of suspected leaks. It was felt that the level to which such monitoring was deployed within the industry varied widely and even within companies may vary between divisions according to the type of system, determined risk of failure and operating philosophy.

Gulf of Mexico, pipeline configurations sometimes consist of smaller branch lines hot-tapped into larger diameter transmission lines. During the hot tap operations the cut out coupon from the transmission pipelines are inspected and provide some useful but limited data indicative of the levels of internal and external corrosion along the line.

Ultrasonic wall thickness readings of topsides component piping are used to indicate local condition of piping and results may in some cases be appropriately interpreted to indicate general line condition.

Inhibitors are used extensively as demanded by system fluid composition to control internal corrosion. Monitoring of dosage and monitoring of insertion coupons are two common methods of assuring prevention of damage or assessing potential for damage.

In certain cases diver or ROV fly-over is used to identify gross defects and the status of burial and condition of anodes and coating. In addition, operational knowledge arising from construction activities (crossings, tie-ins etc.) is used to provide an overview of the condition of existing lines, including the presence of spans, external coating quality and integrity of anodes.

The two most significant causes of defects, relevant to the structural integrity of the pipelines are perceived to be third party interference and internal corrosion. The former is felt to be mostly associated with anchor and anchor line snagging.

Construction activity was felt to present a significant risk of damage to existing and new pipelines. The company often chooses to place an inspector on third party vessels during construction activities on, or adjacent to, their pipelines to improve communication and monitor activity, thereby reducing risk of damage.

The company reported that external corrosion was not, generally, a problem for pipelines in the Gulf of Mexico. The sacrificial anode system has been shown to provide successful lifetime protection against external corrosion. Some isolated problems had been encountered with faulty anodes, which were traced to fabrication and/or material defects in the anodes themselves. In such cases anode retrofitting was required.

The company reported that in the Gulf of Mexico, defects associated with the development of long spans were not significant. In a few instances seabed scour local to the pipeline riser had resulted in increased spans.

Pipeline exposure in shallow water close to shore and at shore-crossings is of concern due to the potential in some areas for increased risk of boat impact.

The philosophy of the company with regard to defect assessment was to apply the recommendations of codes or standards such as ASME/ANSI B31G to detected defects. For defects not specifically addressed in Industry codes or standards, the procedure often used is to undertake risk-based assessments, incorporating a conservative analytical approach to defect acceptability. The assessment results are used to decide if and when to repair/replace the pipeline defect or to implement risk mitigation measures such as on-going monitoring.

The Corporation does not presently employ a blanket information management system for the global sum of pipeline systems. Businesses may employ these systems individually. There is a desire to implement such a system where the potential advantages are apparent. A number of technological, corporate and administrative influences and factors make the implementation of a worldwide assets pipeline database system difficult to design and implement. Efforts are on going in this area and technology is advancing to make this more feasible. In general, information transfer and sharing of knowledge between businesses has been greatly enhanced by technology in recent years.

INTERVIEW: Operator No. 5

The company operates approximately 450 miles of pipeline in the Gulf of Mexico, ranging in size from 2″ to 24″, most in the 6″ to 12″ range. The hydrocarbon inventory is about 50% wet gas and about 50% oil and water. In accordance with the regulatory requirements pipe in water depths of less than 200' are trenched (not buried) whilst over 200' the lines are typically placed directly on the seabed.

The company use API 5L as the standard for line-pipe specification. For some applications additional requirements designed to improve weld quality and ductility are specified, for example, equivalent carbon content is restricted to <0.4% and weld NDT requirements are extended from that required by the code.

Materials grades from X42 to X65 are typical and, hence, the operator has had no experience of defect issues pertaining to high strength steels. Fusion bonded external coating systems are applied with shrink sleeves across weld areas. Concrete weight coating applied as required. Internal coating is not generally used.

The company is in the process of implementing a risk-based prioritization scheme for pipeline inspection. The prioritization is based on the product of the probability of damage occurrence and consequence of failure. It is felt that the overall risk of operating sub sea pipelines is low in comparison with other on shore or platform based operations carried out by the company, and the requirement to inspect is viewed in this broader operational context.

Routine inspections are not implemented for the pipeline system. Some experience exists with the use of standard intensity MFL pigs for deepwater lines offshore California where regulations require inspection. No real problems were discovered in the inspections. Future inspections may use more recent high-resolution systems.

Inspections, when performed, are seeking mainly internal corrosion defects, which are the most prevalent based on operational experience.

The company does not perform external pipeline inspections in the Gulf of Mexico due to the low visibility and the fact that the pipelines are generally buried.

The major cause of loss of pipeline integrity, resulting in loss of inventory, was stated to be third party interference. The most numerous defects were reported to be internal corrosion. Failures due to mudslides during hurricanes had also been experienced. High levels of confidence were expressed in the ability of the sacrificial anode system to prevent serious external corrosion defects and this type of defect was not considered significant in the Gulf of Mexico.

The philosophy of the company with regard to defect assessment was to apply the recommendations of ASME/ANSI B31G to detected corrosion defects. For defects out with the acceptance criteria contained in the code the company policy was to either repair/replace the line segment or to closely monitor for leaks. However, where problems with internal corrosion had occurred in risers and some major transmission pipelines sophisticated finite element methods had been employed to quantify remaining capacity. The company was supportive of the need for industry to develop more sophisticated tools for defect assessment in partnership with the regulatory authorities.

APPENDIX B: SUMMARIES OF PAPERS ON INSPECTION TECHNIQUES

IPC 98- 309 (Ref. 196)

Non-Destructive Techniques for Measurement and Assessment of Corrosion Damage on Pipelines

Richard Kania
RTD Quality Services Inc.

Three systems are discussed:

1. Laser-Based Pipeline Corrosion Assessment System

   The system consists of a laser-based range sensor, signal processing computer, and a gantry frame. It was designed to improve assessing the extent of external corrosion on exposed natural gas and oil pipeline (pit gauge, depth micrometers). The data gathered by laser can be readily digitized to provide a permanent record and colour map of corrosion defects.

2. Semi Automatic Ultrasonic System –Mapscaner

   To obtain quantitative results to establish the severity of metal loss or to determine the suitability of a pipe segment for continued use, RTD Mapscan, a tool which use a hand held ultrasonic probe

3. Magnetic Flux Leakage Scanner – Pipescaner

   MFL technique provides qualitative results and can give a good indication of general condition of a pipeline section, MFL is a well known mature technique, extensively used in self-contained smart pigs. A permanent magnet generates a magnetic field in the pipe wall. Internal and external volumetric defects, general corrosion or pitting, cause disturbance in the magnetic field flow, which can be detected by a Hall effect sensor.

Corrosion assessment procedures use the RSTRENG program.

IPC 98 – 327 (Ref. 198)

EMAT generation of Horizontally Polarized Guided Shear Waves for Ultrasonic Pipe Inspection

Julie Gauthier
Tektrend International, Inc

An ultrasonic-guided wave inspection technique to detect and locate defects in pipes using SH (Horizontally Polarized Shear) plane waves.

Standard ultrasonic techniques applied for the non-destructive testing (NDT) of pipes include the straight beam method using longitudinal waves and the angle beam method using vertical shear (SV) waves.

SH plate waves are a family of Lamb waves. These waves can propagate in plate-like structures of a few wavelengths thick or even of the order of one wavelength. They are two dimensional stress waves in infinite plate structures whose surfaces are free of stresses. Their propagation characteristics are tailored to the geometry of the structure inspected. Their elastic motion covers the whole thickness of the structures (wave-guided) due to the guiding effect of the inner and outer surfaces of the pipe. SH-plate waves have small divergence losses and are attenuated less rapidly than bulk waves, resulting in longer propagation ranges than those for bulk wave with the same frequency and higher sensitivity for defect detection. Furthermore, SH-plate waves can follow curvature thus enabling inspection along bends and other irregular geometry.

IPC 98 – 335 (Ref. 199)

An Automatic ACFM peak Detection algorithm with Potential for Locating SCC Clusters on Transmission Pipelines

L. Blair Carroll

The Alternating Current Field Measurement (ACFM) crack detection and sizing technique has demonstrated its potential as a stress corrosion cracking (SCC) characterization tool.

ACFM is a commercially available NDT technology that was developed for surface crack detection and sizing on coated carbon steel weldments. It was first introduced in the early 1990's by Technical Software Consultants of the UK. The scope of its application has since spread to include sub-surface crack detection in stainless steels up to 30 mm thick, the detection and sizing of corrosion pitting, airframe inspection and drill thread inspection.

IPC-98 - 351 (Ref. 201)

Mechanical Development of a NPS 36 Speed Controlled Pipeline Corrosion Measurement Tool

Robert S Evenson
BJ Pipeline Inspection Services

A large bypass, variable speed NPS 36 MFL, corrosion inspection tool has been developed and run successfully in several high-pressure natural gas pipelines without noticeable impact on operational throughput.

Since the first in-line MFL tool was introduced in 1965, a variety of conventional (low) and high-resolution MFL tools have been devised for measuring pipeline corrosion. A slow MFL tool speed, normally less than 4 m/s, is required. Reducing pipeline flow throughput velocity to provide an optimum MFL measurement was accepted standard for MFL corrosion measurement. Low MFL tool measurement speed and lack of active speed control bypass capacities generally resulted in a plethora of economic and operational problems for high-pressure natural gas pipeline operators.

Tool speed reduction in a pressure gas pipeline can be accomplished through a combination of flow bypass and tool drag. Adequate friction must be introduced to counteract the force created by the differential pressure across the tool. A fixed bypass (Passive speed control) can achieve the desired effect; however, variations in flow, pipe slope and wall thickness cannot be adjusted for. Constant inspection velocity is fundamental for enduring accurate evaluation and sizing of corrosion defects. This can be realized using a variable bypass (Active speed control).

IPC-98 – 367 (Ref. 203)

The Operational Experience and Advantages of using Speed Control Technology for Internal Inspection

Reena Sahney
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Speed control technology was still in the early stages of development and performance testing. The purpose of speed control is to reduce capacity restrictions while maintaining the optimal speed for data collection. Constant tool speed also improves data quality, as MFL signals are asymmetric under dynamic conditions. The basic mechanism of speed control involves bypassing gas such that the tool speed is slower than the gas speed. This is accomplished through a valve and controller that respond to changes in gas velocity in order to maintain a pre-set tool speed. The amount of gas being bypassed is obviously sensitive to pressure and temperature.

By mid 1997, two vendors had successfully completed MFL inspections on the TCPL system with speed control technology.

IPC-98 - 379 (Ref. 205)

The Changing Role of Inspection

Keith Grimes
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The changing role of Inspection and industry's expectations of it are addressed in the paper.

Tuboscope were pioneers of smart pigging with their Linalog Magnetic Flux Leakage (MFL) pigs for pipeline surveys from the mid 1960's onward. This was a remarkably advanced technology for its day, giving pipeline operators their first early warning of major pipeline problem. The inspection log was essentially qualitative, with some degree of defect severity grading. In the mid 1970's British Gas and Battelle had completed major investigation programs on pipeline material properties and failure mechanisms. This work lead to the definition of quantitative performance requirements for smart pigs to be able to reliably replace hydrotesting as a means of revalidating pipelines. British Gas developed its first high-resolution inspection tools, operating to these specifications, in the late 1970's. Some years later, during the mid 1980's, Pipetronix and NKK developed the alternative ultrasonic technique (UT) using liquid coupling.

Where industry is now:

Inspection specifications: 10/20 sizing specifications. Defects above these depths are detected and sized to +/- 10% wall thickness.

Girthweld Defects: Corrosion problems often occur preferentially at girth welds due to failure of field coatings at joints or preferential internal corrosion/erosion at the girth weld. The ability to inspect girth welds has been taken further to detect and size circumferential cracking.

Long Axial Corrosion including channeling: this form of corrosion is often seen alongside the seam weld in tape wrapped pipe. Conventional MFL has a limited sensitivity to such features. Normal wave ultrasonic has the ability to see the plateau corrosion but has problems in gauging the depth of narrow channels and can be troubled by variable geometry at the corroded seam weld. BG's solution is to produce a Transverse Field Inspection (TFI) system where the magnetic flux path is circumferential around the pipe. This system is now tuned to give preferential detection of axial/channeling defects.

The Poor field Coating Problem: Inspection system was re-calibrated to look specifically for the onset of low level corrosion around the pipe joints.

The Highly Stressed Pipeline: The MFL interpretation task gives an indication of these high stress levels. It does not provide a high resolution mapping of detailed stress pattern in the pipeline. Other techniques under development may be able to provide this information in the future.

Hard spot Inspection: BG's work has demonstrated the ability to detect and size the extent of hard spots using low saturation magnetic techniques.

Inspection for Stress Corrosion Cracking (SCC): Longitudinally aligned planar defects such as SCC cracking and longitudinal internal Seam Fatigue cracking pose particular problems for on-line inspection technologies because of the inherent variability of the defect, and the presence in many pipeline steels of benign defects which can be confused with cracks.

Ultrasonic techniques are very sensitive to planar defects such as cracks and laminations. A major operational problem with ultrasonic pigs in gas pipelines is the necessity for a liquid couplant, meaning that either the line has to be flooded or a liquid slug introduced to carry the tool. One remarkable feature of the BG crack tool is the use of transducers mounted within special probe wheels, which provide acoustic coupling without the need for flooding or liquid slug in the pipeline. By looking around the pipe circumference, these sensors provide 100% high-resolution coverage of the whole pipe wall, including the seam weld.

In addition to ultrasonics as a solution to the SCC inspection problem, work performed on the Transverse field MFL inspection system has shown some ability to detect colonies of SCC in line pipe magnetically, although the full capacity is not yet established.

IPC-98 – 589 (Ref. 226)

The Canadian Energy Pipeline Association Stress Corrosion Cracking Database

Bruce R. Dupuis
Foothill Pipe Lines Ltd.

The SCC database was initiated by the CEPA(Canadian Energy Pipeline Association). The current generation of the database has a broad scope, containing detailed data for every colony and its associated environmental conditions. The database also includes corrosion and dents amongst other integrity concerns to identify any correlation with SCC and provide a common industry data format to investigate these and other integrity issues.

IPC-98 – 595 (No. 227)

Use of the Elastic Wave Tool to Locate Cracks along the DSAW Welds in a 32-inch OD Products Pipeline

Willard A. Maxey, Raymond E. Mesloh
Kiefner and Associates, Inc

The effectiveness of the British Gas elastic wave in-line inspection tool for finding and characterizing along DSAW seams was clearly demonstrated by its use.

In-line Inspection tools for Cracks Detection in Gas and Liquid Pipelines

H.H Willems, and O.A. Barbian
Pipetronix GmbH

Cracks in pipelines are among the most severe and potentially dangerous defects in pipelines. The mechanism of initiation and growth in particular of the so called near neutral SCC are still not fully understood and are the subject of ongoing research. SCC can occur in various forms from small isolated cracks to large crack fields containing hundreds of cracks. Since the hoop stress is usually the driving force, SCC is normally axially orientated. SCC is generally found on the external pipe surface with some preference in the longitudinal weld area but also in the base material. Its occurrence is observed largely concerning coating failure.

For a long time, the use of hydrostatic testing was considered the only reliable way to prove the integrity of a pipeline that was a candidate for SCC attack. This type of test is expected to remove all critical cracks, i.e. cracks that could cause failure under normal operating conditions. However, since no information on sub-critical cracks is obtained the estimation of the safe future service life becomes rather uncertain. Moreover, hydrostatic testing can cause crack growth of near critical cracks thus reducing the expected safety margin. Additionally, hydrostatic tests are expensive and time consuming, as the line has to be taken out of service.

Another approach to find SCC in pipelines relies on predictive models and investigative excavation. The effectiveness of predictive models (soil models) for finding sites assumed to be susceptible to significant SCC depends on a number of parameters thus making this method unsuitable for detection and prioritization of SCC.

The UltraScan CD is an in-line inspection tool developed with the goal to reliably detect and size cracks and related crack-like defects in pipelines. It is a superior alternative to hydrostatic retesting and the other approaches mentioned.

The UltraScan CD is based on using 45° shear waves, which are generated in the pipe wall by angular transmission of ultrasonic pulses through a liquid coupling medium. This is a standard technique for ultrasonic crack inspection established many years ago (Krautkramer, 1986)

Because SCC is generally oriented perpendicularly to the main stress components, i.e, to the hoop stress, the ultrasonic pulses are injected in a circumferential direction to obtain maximum acoustic response.

IPC –96- 345 (Ref. 136)

Internal Inspection Device for Detection of Longitudinal Cracks in Oil and Gas Pipelines – Results from an Operational Experience

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PipeTronix, Germany

Pipetronix has develop a new generation of internal inspection device for the detection of cracks in pipelines. Since its commercial introduction in October 1994 the tool, UltraScan CD, has successfully inspected nearly 1,000 km of operating oil and gas pipelines. The performance has proved the UltraScan CD to be a reliable internal inspection device for the detection of Cracks (SCC, Fatigue and other crack like defects) in pipelines. As a result, the German TUV has approved the use of UltraScan CD as a substitute for hydrostatic pressure testing of pipeline.

The new tool is based on the ultrasonic technique since only ultrasonic allows for the in-line detection of external as well as internal cracks with the necessary sensitivity and high resolution. The technique applied uses shear waves, which are generated in the pipe wall by angular transmission of the ultrasonic pulses through a liquid coupling medium (oil, water etc). The angle of incidence is adjusted such that a propagation angle of 45 is obtained in pipeline steel. This technique has proven appropriate for crack inspection and it is established as one of the standard techniques in ultrasonic testing.

IPC 1996 – 329 (Ref. 134)

R&D Advance in Corrosion and Crack Monitoring For Oil and Gas Lines

D.L. Atherton
Queen's University

Magnetic Flux Leakage (MFL) inspection techniques for in-line corrosion monitoring of pipelines continue to evolve rapidly. Current R&D is aimed at improving the accuracy and reliability and consequent need to characterize the magnetic properties of the pipes and effects of line pressure, residual and bending stresses on MFL signals. Magnetic Barkhausen Noise (MBN) measurements are being used to study the stress-induced changes in magnetic anisotropy. Remote Field Eddy Current (RFEC) Techniques are being investigated for detection and measurement of stress corrosion cracking in gas pipelines.

Smart pigs using MFL detectors are still the most cost-effective method of inspecting pipelines for corrosion. The general advent of high-resolution tools and the introduction of extra high-resolution tools have more precise defect sizing. Depth indications correct to 5% are desired so that accurate fracture mechanics calculations of maximum allowable operating pressure can be made. The MFL signal depends not only on the defect and tool characteristics but also on the running conditions, such as line pressure stress, and on the magnetic properties of the particular line pipe, which vary greatly.

Crack detection and measurement are much more difficult challenges than corrosion monitoring. The techniques currently under development are ultrasonic and electromagnetic, specially the Remote Field Eddy Current (RFEC) method. In gas lines it is difficult to couple ultrasonic energy efficiently into and from the pipe wall; signal processing, or rather discrimination, is also proving to be a serious problem, partly because of the relatively small number of sensors which can be used. Whilst results from high resolution ultrasonic detection tools in liquid lines are encouraging, there is resistance to the use of liquid slugs in gas lines, although more valuable data is obtained than from a simple hydrostatic test.

An RFEC tool uses a relatively large internal coaxial solenoidal exciter coil driven with low frequency AC. They can detect defects on the inside or the outside of the pipe wall with approximately equal sensitivity. RFEC probes use both phase and amplitude information to give both signal discrimination and defect measurement.

Integrity Assessment of Offshore Pipelines by Use of Intelligent Inspection Tools

M. Beller And W. Garrow
Pipetronix GmbH

As the international pipeline systems are growing in age it is of ever increasing importance that operators are supplied with the technology to inspect and assess the state of their pipeline. It is for this reason that inspection tools have been developed and introduced into the market utilizing non-destructive testing techniques (NDT) to inspect pipelines without the need of a shut down during the survey. These vehicles are generally known as on-line inspection tools or intelligent pigs. Furthermore with the introduction of large diameter, high pressure offshore lines for oil or gas in the last twenty years and constant addition to this offshore network on a worldwide scale intelligent pigs are increasingly being used in the commissioning stage in order to perform base-line surveys.

Basically flaws and defects in pipelines can be distinguished into one of the following categories: Geometric Anomalies; Metal Loss; Cracks or Crack like Defects.

Geometric anomalies related to any change in the geometry of a pipe such as dents, ovalities or wrinkles etc. Two of reasons are a critical reduction in free internal diameter and the formation of locally acting stress concentrations. Regular or intelligent pigs are used.

Metal Loss features usually relate to internal or external corrosion. Intelligent corrosion detection pigs must therefore be able to reliably detect and measure corrosion flaws and to accurately locate them.

The following types of cracks can be found in pipelines: Fatigue cracks; Stress Corrosion Cracks; Sulfide Stress Corrosion Cracks. The types of potential defects for onshore and offshore installations are similar, although the frequencies with which they occur are different. Whilst most failures of onshore pipelines are attributed to third party mechanical interference, most defects in offshore lines are caused by corrosion.

Pipeline & Gas Industry (Ref. 258)

Stress Corrosion Crack In-Line Pig Shows Promise in Tests

Keith Grimes
British Gas, Inspection Services, Inc., Houston

Stress corrosion cracks, the most difficult pipeline defect to detect with a survey pig, may soon yield to in-line inspection technology.

Inline inspection techniques – smart pigs – to detect and quantify the first two defect categories (Geometric Deformation: dents, ovality; Metal Loss: corrosion, mechanical damage), have gained wide acceptance in recent years and many pipeline operators have instituted regular inspection programmes to aid maintenance and assure pipe integrity.

Cracks have proved to be the most difficult to detect. There currently is no commercially available in-line inspection system with proven crack detection capacity. BG developed a pig-based system to detect and size longitudinal cracks.

Technique:

A method, which utilizes elastic waves at ultrasonic frequency, was selected as the basis for development. Ultrasonic waves are injected into the pipe wall so that they travel circumferentially around the pipe and are detected when they are reflected from axial cracks. Elastic waves are transmitted in both directions to allow a comparison of echoes from both sides of the reflector.

Because high frequency elastic waves will not propagate through gas, the essential requirement is for some means of transmitting the energy into the pipe wall without excessive attenuation.

(Ref. 262)

Which Smart Pig Do I Choose? A Comparison of Magnetic Flux Leakage Technologies From an Operator's Viewpoint

Ken Plaizier

We used hydro testing as an inspection method every five years up to the mid-1980's. Without hydro testing as an inspection option, smart pigs become the option of choice.

Our division began using magnetic flux leakage (MFL) smart pigs in the early 1980's to assess pipeline integrity. Low resolution MFL tool in 1989.

To know the priority in which lines should be inspected, a risk assessment first needs to be developed by each pipeline company. Each pipeline segment we operate was evaluated as to the probability and consequence of a leak, and numerical values assigned to each segment.

Smart Pig Evaluation:

Low Resolution Magnetic Leakage Tools:

These smart pigs have been around for some time, and have produced satisfactory results for many pipeline operators. While unable to differentiate between internal and external defects, they can detect the majority of defects in pipelines. Costs for this tool typically run between $600 and $1200 per mile.

High Resolution Magnetic Leakage Tools:

An exciting and more costly new alternative for pipeline operators, "high-resolution" MFL tools come in limited sizes. Cost for this tool typically will cost $1500 to $4000 per mile.

Ultrasonic Tools:

These smart pigs use ultrasonic technology to measure remaining pipe wall thickness. Until very recently these smart pigs have not been able to inspect thin-wall pipe (≤0.250). Even now, the technology for inspecting thin walls is somewhat difficult, if not untested, using third-wave processing. There are other limitations with this type of tool, such as requiring a couplant, being able to detect small pits with sharp wall shapes, etc., which may be a factor for the operator.

PPITC-1992 (Ref. 259)

Inspection Technologies for a Wide Range of Pipeline Defects

Keith Grimes

The main investment has been concerned with metal loss inspection using highly developed magnetic flux leakage technology. British gas has developed two unique systems for the detection and measurement of the other major causes of pipeline failure.

The elastic wave system is designed to detect longitudinal cracks, while the burial and coating system inspects offshore pipelines for free spanning, pipeline exposure and damage to the weight coating.

Metal Loss:

In common with most other pipeline operators, British Gas identified metal loss, cause by mechanical interference and corrosion mechanisms, to be the most likely cause of pipeline failure. British Gas took MFL basic techniques and introduced major refinements and engineering innovations.

Crack Detection:

Of all the forms of planar defect that can occur in a pipeline, those oriented radially and longitudinally have the greatest structural significance. Two such types of crack are the result of fatigue and stress corrosion.

A method, which utilizes elastic waves at ultrasonic frequencies, was selected as the basis for development.

Burial and Coating:

Offshore pipeline operators have adopted sub sea surveillance methods to inspect for the following threats to pipeline integrity:

1. Exposure of the pipeline on the seabed
2. Damage to, or loss of, concrete weight coatings;
3. Presence and nature of unsupported spans.

Current techniques employ such methods as sidescan sonar, sub-bottom profilers, ROV and diver visual survey. These techniques, particularly diver and ROV survey are expensive.

A pig-based system has obviously advantages. Firstly the pig cannot drift unknowingly off the pipeline. Secondly, the quality and timing of the inspection are not affected by sub sea visibility or weather conditions, and thirdly, shallow waters and intertidal area can all be inspected in the same inspection mission.

The inspection technique employed is based on a neutron-interrogation method. The core of the vehicle holds a neutron source, normally held within a radiation shield, but capable of being exposed when required. Once the source is exposed, neutrons pass through the pipeline steel and the concrete coating into the surrounding medium.

The neutrons interact with the surrounding material, producing radiation characteristic of the composition of that material. Some of the characteristic radiation travels back into the pipeline and is detected by sensing units mounted circumferentially around the pig. The data is then recorded by the on board electronics.

(Ref. 263)

In-Line Inspection Technologies for Mechanical Damage and SCC in Pipelines

Final Report on Tasks 1 and 2

T. A. Bubenik, J.B. Nestleroth
Battelle

This report is a summary of work conducted for the U.S. Department of Transportation Office of Pipeline Safety under a research and development contract entitled "In-Line Inspection Technologies for Mechanical Damage and SCC in Pipelines". This project is evaluating and developing in-line inspection technologies for detecting mechanical damage and cracking in natural gas transmission and hazardous liquid pipelines.

Task 1: Mechanical Damage

Mechanical damage is the single largest cause of failure on gas-transmission pipelines today and a leading cause of failures on liquid transmission lines. Mechanical damage defects typically show a number of features, such as denting, metal movement, and cold working. The most significant of these features from the perspective of defect severity are the size and extent of the cold worked region.

From an inspection perspective, cold work and residual stresses and strains change the magnetic properties of the steel, confounding inspection results. Denting changes the orientation of the pipe wall with respect to the fixed orientation of sensors on an inspection tool. And removed metal produces a signal of its own, adding further complexity.

MFL has been shown to be capable of detecting some mechanical damage. Part of the signal generated at the site of the mechanical damage is due to geometric change – for example, a reduction in wall thickness due to metal loss causes an increase in measured flux and sensor/pipe separation. Other parts of the signal are due to change in magnetic properties that result from stresses, strains, or damage to the microstructure of the steel.

Inspection-tool variables, such as the strength of the applied magnetic field, impact the ability to detect and characterized defects.

Inspection –run variables, such as tool velocity and line pressure, also impact the results. Velocity reduces the strength of MFL signals. Pressure affects the stresses in the pipe wall (and adds stresses around dents and gouges), which in turn change the magnetic properties of the pipe steel.

MFL signals for metal loss, dents, cold work, residual stress, and plastic strains are fundamentally different signal components as a means of assessing the severity of mechanical damage defect.

MFL inspection tools that are designed to detect metal-loss corrosion are not optimized for detecting mechanical damage. These tools use high magnetic fields to suppress noise sources due to stresses and micro structural change, such as cold work, which diminish sizing accuracy for corrosion. However, a mechanical-damage tool needs to detect changes in microstructure and stress.

MFL is the most commonly used in-line inspection method for the detection of corrosion in pipelines, extending this technology for mechanical damage would simplify and have many practical and economic benefits.

Analysis Methodologies:

a. Feature Based Analysis Methods

Feature-based analysis methods make use of discrete signal parameters, such as peak amplitude or peak-to-peak amplitude. Peak amplitude is tha maximum recorded value in an inspection signal, and peak-to-peak amplitude is the difference between the maximum and minimum recorded value in an inspection signal.

To improve the ability to reliably detect, classify, and size mechanical damage defects, Battelle developed a multiple magnetization approach. The approach requires two magnetizing levels: high level for detecting geometric deformation and low level for detecting both magnetic and geometric deformation. Classifying and determining the severity of the damage requires additional signal processing. Decoupling is used to extract unique signal due to geometric and magnetic deformation. Using the geometric and magnetic signal, different types of damage become apparent.

b. Nonlinear harmonic Methodologies

The nonlinear harmonic method is an electro-magnetic technique that is sensitive to the state of applied stress and plastic deformation in steel. A sinusoidal magnetic field is applied at a fixed frequency. Odd-numbered harmonic of that frequency are generated because of the nonlinear magnetic characteristics of ferromagnetic materials. Detecting and measuring the harmonic signal can infer changes in magnetic properties.

c. Neural Network analysis Methods

A neutral network analysis method used a large number of relatively simple calculations to make a prediction. As an example, a neutral network might be designed to predict the shape of a corrosion detect or classify a possible defect based on information contained in the MFL signal.

Three kinds of neutral networks for characterizing mechanical damage were developed and evaluated at Iowa State University. The results from this work demonstrate the feasibility of using a neutral network approach for differentiating between mechanical damage and corrosion, characterizing defect profiles from MFL signals.

Task 2: Cracking

Stress-corrosion cracking (SCC) is a complex phenomenon associated with several in service and hydrostatic restest failures on gas and liquid pipelines. The exact mechanisms that lead to SCC and the field and operating conditions that affect cracking are the subject of ongoing research.

Intergranular SCC usually occurs in colonies, where the cracks are often branched and irregular at their tips. As a result, using ultrasonic techniques to measure crack-tip signals for sizing is difficult. The difficulty is compounded by the presence of background signal from ultrasonic energy that are scattered by the crack face reflected off the nearby pipe surface, and converted from one mode to another at interface.

Inspection Techniques:

There are a number of problems associated with sizing near-surface axial cracks from the out side surface of the pipe. A primary difficulty is the inability of conventional ultrasonic procedure, such as shear-wave and amplitude based techniques, to locate the end points of the flaw in both the axial and through wall direction.

The SwRI techniques are termed SLIC, which refers to the simultaneous use of shear and longitudinal waves to inspect and characterized flaws. The techniques were developed in the 1980s and early 1990s.

Four techniques using the SLIC systems were evaluated for sizing cracks: amplitude-drop, phase-comparison, peak-each, and satellite-pulse. Each technique was calibrated against four electro-discharge machine (EDM) axial notches placed in one of the test specimens. The amplitude drop technique was used for estimating the crack lengths. The phase-comparison technique in conjunction with the peak-echo and satellite-pull techniques were used for depth.

One of the reasons that many cracks cannot be effectively detected and characterized by current MFL tools is that the applied magnetic field has an orientation parallel to axial cracks, such as those due to SCC. Velocity-induced remote-field effects and current perturbation has strong components that are oriented preferentially for detecting axial cracks.

In order to investigate the feasibility of the technique, a three-dimensional finite element model for simulating the velocity-induced fields in the remote region and the effect of cracks on these fields was developed.

Like velocity-induced remote-field techniques, remote-field eddy-current techniques are sensitive to axial crack-like defects. The fundamental difference between this technique and the one discussed above is in the generation of the source electromagnetic field. The remote-field eddy-current technique uses a sinusoidal current flowing in an exciter coil to induce currents in the pipe, while the velocity-induced remote-filed technique uses the permanent magnets on the inspection tool.

(Ref. 264)

Offshore Pipeline Girth Welds: Non-Destructive Testing

P.J. Mudge
Welding Institute

Non destructive testing is an important activity in the pipe laying process, it being applied to prevent defects in girth welds made in the field, which are outside the limits imposed by the appropriate code, being present when the pipeline enters service. Consequently, the purpose of this programme was to provide sufficient information about both conventional NDT techniques already in use. In order to enable recommendations to be made concerning optimum use of NDT, the performance of NDT has been examined in the context of ensuring that girth welds meet the requirement of the specified standards.

Four techniques have been considered:

(i) The widely used panoramic radiography, with an X-ray crawler inside the pipe and a film wrapped around the joint on the outside.

(ii) Manual ultrasonics, which in some instances is used for localized testing;

(iii) Mechanized ultrasonics, which is capable of scanning the whole weld, but which has yet to gain wide acceptance; and

(iv) Real time filmless radiography, which is under development, but has the advantage of eliminating the difficulties of rapid film processing and viewing and has the potential to make interpretation easier.

To achieve 100% examination of the weld volume, panoramic X-radiography is widely used, with the source situation inside the pipe and positioned on the axis, and the film wrapped around the outside of the joint.

For small diameter pipes (usually less than around 250mm diameter), a gamma ray-emitting isotope placed inside the pipe is used as the source of radiation, or alternatively a double wall exposure is taken with both film and radiation source (X or gamma) outside the pipe.

Manual ultrasonics is employed in some cases for localized testing where the radiography has detected a discontinuity, which is marginally acceptable or reject able according to code requirements. Magnetic particle inspection is used on a similar basis when surface breaking defects are suspected.

A device has been built which allow ultrasonic probes to be transported around the joint circumference by a mechanized scanner, so that the entire weld can be tested ultrasonically.

APPENDIX C: SUMMARIES OF PAPERS ON DEFECT ASSESSMENT METHODS

(Ref. 4)

Manual for Determining the Remaining Strength of Corroded Pipelines

ASME B31G-1991

This criterion for corroded pipe to remain in service presented in this manual is based only upon the ability of the pipe to maintain structural integrity under internal pressure. It should not be the sole criterion when the pipe is subject to significant secondary stress (e.g. bending), particularly if the corrosion has a significant transverse component.

Determination of Maximum allowable Longitudinal Extent of Corrosion

A contiguous corroded area having a maximum depth of more than 10% but less than 80% of the nominal wall thickness of the pipe should not extend along the longitudinal axis of the pipe for a distance greater than the calculated from:

$$L = 1.12B\sqrt{Dt}$$

L= maximum allowable longitudinal extent of the corroded area, D=nominal outside diameter of the pipe, B= a value which may be determine from the following formula:

$$B = \sqrt{\left(\frac{d/t}{1.1d/t - 0.15}\right)^2 - 1}$$

B may not exceed the Value 4. If the corrosion depth is between 10% and 17.5%, use B=4.0.

Determination of Remaining Strength

If the measure maximum depth of the corroded area is greater than 10% of the nominal wall thickness but less than 80% of the nominal wall thickness and the measured longitudinal extent of the corroded area is greater than the value determined from the above equation, calculate:

$$A = 0.893\left(\frac{L_m}{\sqrt{Dt}}\right)$$

L_m = measured longitudinal extent of the corroded area.

For value of A less than or equal to 4.0, then the safe maximum pressure for the corroded area is given as below:

$$P^{'} = 1.1P\left[\frac{1-\frac{2}{3}\left(\frac{d}{t}\right)}{1-\frac{2}{3}\left(\frac{d}{t\sqrt{A^2+1}}\right)}\right]$$

where P=2StFT/D , S =SMYS

If value of A greater than 4.0

$$P^{'} = 1.1P\left[1-\frac{d}{t}\right]$$

except the $P^{'}$ may not exceed P.

It is recognized that most field operators will prefer a simple method of evaluating a corroded area. Therefore, tables for corrosion limits evaluate and place the results in tabular form. This allows the field operator to make decisions simply by going to a table after measuring the longitudinal extent and maximum depth of the corroded area and making a choice.

(Ref. 378)

Corroded Pipelines

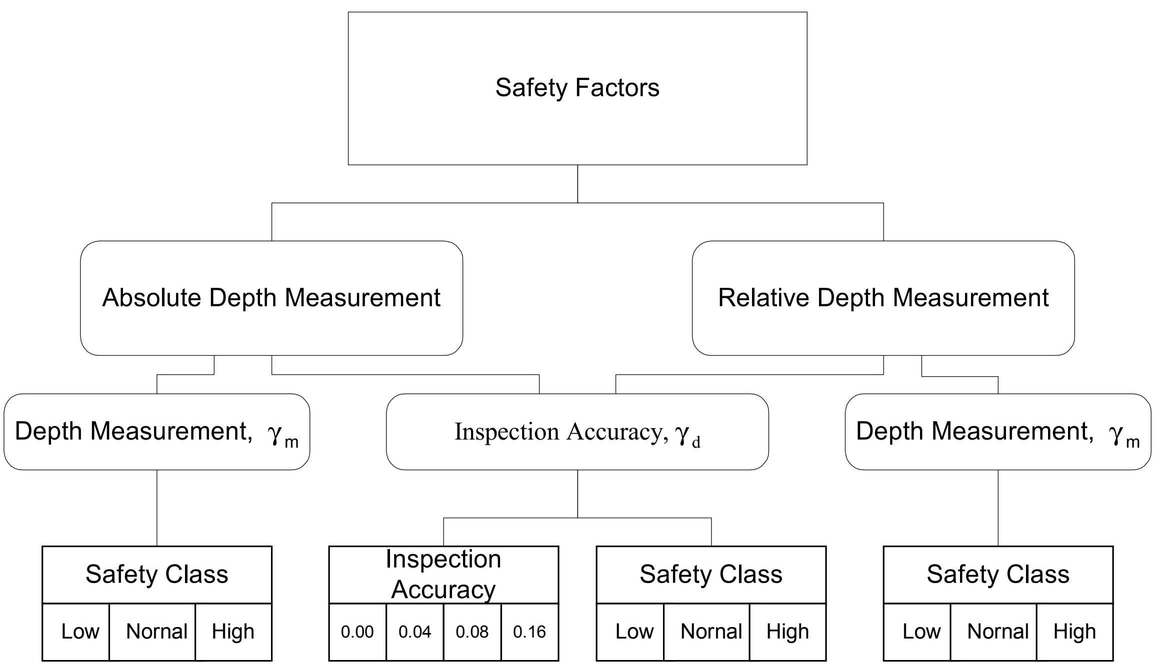
DNV Recommended Practice RP-F101 1999

This Recommended Practice provides the methods for assessing pipelines containing corrosion defects. It is the results of co-operation between BG Technology and DNV. This RP gives two alternative approaches to the assessment of corrosion. First one is Partial Safety Factor method based on the LRFD methodology. Another is allowable stress approach.

This is the first codified and comprehensive recommended practice on the pipeline corrosion defect assessment. It provides not only the assessment of single defects of different shapes under either pressure or combined loadings, but also the assessment of the interacting corrosion defects.

Part A – Partial Safety Factor:

The approach given in this part is based on the reliability calibration. The safety factors are given for two general inspection methods (based on relative measurements e.g. magnetic flux leakage, and based on absolute measurements e.g. ultrasonic), four different levels of inspection accuracy, and three different reliability levels corresponding to the safety class. See following diagram for the categories of the safety factors.



Assessment of a Single Defect

A defect can be treated as an isolated defect if any of the following conditions are satisfied:

a). the circumferential angular spacing between adjacent defects $\phi \rangle 360\sqrt{\frac{t}{D}}$ (degree)

b). the axial spacing between adjacent defect, $s \rangle 2.0\sqrt{Dt}$

1. Longitudinal Corrosion Defect, Internal Pressure Loading only

The allowable corroded pipe pressure of a single defect subject to internal pressure loading only is given by following acceptance equation:

$$p_{corr} = \gamma_m \frac{2tSMTS(1-\gamma_d (d/t)^*}{(D-t)\left(1-\frac{\gamma_d (d/t)^*}{Q}\right)}$$

where

$$Q = \sqrt{1+0.31\left(\frac{l}{\sqrt{Dt}}\right)^2} \text{ and } (d/t)^* = (d/t)_{meas} + \varepsilon_d StD[d/t]$$

SMTS is the Specified Minimum Tensile Strength. For details of γ_m and γ_d see the RP.

2. Longitudinal Corrosion Defect, Internal Pressure and Superimposed Longitudinal Compressive Stresses:

The allowable corroded pipe pressure of a single longitudinal corrosion defect subject to internal pressure and longitudinal compressive stresses can be estimated using the following equation:

$$p_{corr} = \gamma_m \frac{2tSMTS}{(D-t)} \frac{(1-\gamma_d (d/t)^*}{\left(1-\frac{\gamma_d (d/t)^*}{Q}\right)} H_1$$

where:

$$H_1 = \frac{1+\dfrac{\sigma_L}{\xi \quad SMTS}\dfrac{1}{A_r}}{1-\dfrac{\gamma_m}{2\xi A_r}\dfrac{1-\gamma_d (d/t)^*}{\left(1-\frac{\gamma_d (d/t)^*}{Q}\right)}}$$

$$A_r = \left(1-\frac{d}{t}\theta\right)$$

$$\sigma_L = \frac{F_X}{\pi\ (D-t)t} + \frac{4M_Y}{\pi\ (D-t)^2 t}$$

σ_l is the combined nominal longitudinal stress.

3. Circumferential Corrosion Defects, Internal Pressure and Superimposed Longitudinal Compressive Stresses

The allowable corroded pipe pressure of a single circumferential corrosion defect can be estimated using the following equation:

$$p_{corr,circ} = \min\left\{ \gamma_c \frac{2t\,SMTS}{(D-t)} \left[\frac{1 + \dfrac{\sigma_L}{\xi\,SMTS}\dfrac{1}{A}}{1 - \dfrac{\gamma_{mc}}{2\xi}\dfrac{1}{A_r}} \right], \qquad \gamma_{mc}\frac{2tSMTS}{(D-t)} \right\}$$

Assessment of Interacting Defects

The interaction rules are strictly valid for defects subject to only internal pressure loading. The partial safety factors for interacting defects have not been derived from an explicit probabilistic calibration. The partial safety factors for a single defect subject to internal pressure loading have been used.

The allowable corroded pipe pressure of a colony of interacting defects can be estimated using the following procedure; the corroded section of pipeline should be divided into sections of a minimum length of $0.5\sqrt{Dt}$ and at each section a series of axial projection lines with a circumferential angular spacing of $Z = 360\sqrt{\dfrac{t}{D}}$. Where defects overlap, they should be combined to form a composite defect. See F101 for details.

The allowable corroded pipe pressure of each defect, to the Nth defect, treating each defect or composite defect, as a single defect:

$$p_i = \gamma_m \frac{2t\,SMTS}{D-t} \frac{\left(1 - \gamma_d (d_i/t)^*\right)}{\left(1 - \dfrac{\gamma_d (d_i/t)^*}{Q_i}\right)} \qquad i = 1 \cdots N$$

where Q_i and $(d_i/t)^*$ are same as defined for single defect assessment.

The combined length of all combinations of adjacent defects are calculated as below:

$$l_{mm} = l_m + \sum_{i=n}^{i=m-1} (l_i + s_i) \qquad n, m = 1 \cdots N$$

The effective depth of the combined defect formed from all of the interacting defects from n to m are calculated:

$$d_{nm} = \frac{\sum_{i=n}^{i=m} d_i l_i}{l_{nm}}$$

The allowable corroded pipe pressure of the combined defect from n to m, using l_{nm} and d_m in the single defect equation:

$$p_{nm} = \gamma_m \frac{2t\,SMTS}{(D-t)} \frac{\left(1-\gamma_d (d_{nm}/t)^*\right)}{\left(1-\dfrac{\gamma_d (d_{nm}/t)^*}{Q_{nm}}\right)} \qquad n,m = 1 \cdots N$$

where Q_{nm} and $(d_{nm}/t)^*$ are defined as same as above.

The allowable corroded pipe pressure for the current projection line is taken as the minimum of the failure pressure of all of the individual defect, and of all the combinations of individual defects on the current projection line. The allowable corroded pipe pressure for the section of corroded pipe is taken as the minimum of the allowable corroded pipe pressures calculated for each of the projection lines around the circumference.

Assessment of Complex Shaped Defects

This method must only be applied to defects subjected to internal pressure loading only. The partial safety factors for a complex shaped defect have not been derived from an explicit probabilistic calibration. The partial safety factors for a single defect subject to internal pressure loading have been used.

The principal underlying the complex shaped defect method is to determine whether the defect behaves as a single irregular ‘patch’, or whether local ‘pits’ within the patch dominate the failure. Potential interaction between the pits has also to be assessed.

1. The allowable corroded pipe pressure of the total profile, using d_{ave} and l_{total} in the single defect equation:

$$p_{total} = \gamma_m \frac{2t\,SMTS}{D-t} \frac{\left(1-\gamma_d (d_{ave}/t)^*\right)}{\left(1-\dfrac{\gamma_d (d_{ave}/t)^*}{Q_{total}}\right)}$$

where $d_{ave} = \dfrac{A}{l_{total}}$ average depth of the complex shaped defects.

2. The allowable corroded pipe pressure of the idealized 'patch' and the predicted failure pressure of the idealized patch, using l_{total} and d_{patch}.

$$p_{patch} = \gamma_m \frac{2t\,SMTS}{D-t} \frac{\left(1-\gamma_d\left(d_{patch}/t\right)^*\right)}{\left(1-\frac{\gamma_d\left(d_{patch}/t\right)^*}{Q_{total}}\right)}$$

where $d_{patch} = \frac{A_{patch}}{l_{total}}$ average depth of an idealized 'patch'.

3. The allowable corroded pipe pressure of all individual idealized 'pits' as isolated defects, using averaged depth and the longitudinal length of the each idealized pit in the single defect equation:

$$p_i = \gamma_m \frac{2t\,SMTS}{D-t} \frac{\left(1-\gamma_d\left(d_{ei}/t\right)^*\right)}{\left(1-\frac{\gamma_d\left(d_{ei}/t\right)^*}{Q_i}\right)}$$

where $d_{ei} = d_i - (t-t_e)$, $t_e = \frac{p_{cap,patch}\cdot D}{\left(2\left(1.09\cdot SMTS\right)+p_{cap,patch}\right)}$ and

$$p_{cap,patch} = 1.09\frac{2t\,SMTS}{D-t} \frac{\left(1-\left(d_{patch}/t\right)\right)}{\left(1-\frac{\left(d_{patch}/t\right)}{Q_{total}}\right)}$$ is the predicted failure pressure.

4. The allowable corroded pipe pressure of the combined defect from n to m, using $l_{nm,}$ $_te$ *and* $d_{e,nm}$ in the single defect equation:

$$p_{nm} = \gamma_m \frac{2t\,SMTS}{D-t_e} \frac{\left(1-\gamma_d\left(d_{e,nm}/t_e\right)^*\right)}{\left(1-\frac{\gamma_d\left(d_{e,nm}/t_e\right)^*}{Q_{nm}}\right)}$$

Part B – Allowable Stress Approach

The approach in part B is based on the allowable stress design format. The failure pressure is multiplied by a single safety factor based on the original design factor. In the equations of this part, the ultimate tensile strength (UTS) is quoted. If the UTS is not known the SMTS should be used.

The total usage factor to be applied to determine the safe working pressure should be calculated from $F=F_1F_2$. $F_1=0.9$ and F_2 is operational usage factor and taken as equal to the design factor. For the detail equations in this part, see F101.

(Ref. 74)

A Proposed Corrosion Assessment Method and In-Service Safety Factor for Process and Power Piping Facilities

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Development of a Corrosion Assessment Method

Background of the corrosion assessment criterion for pipelines:

Many operators of transportation pipelines already perform in-line inspection and/or hydrostatic testing to verify the safety of their lines. B31.4 and B31.8 are unique among B31 design codes in that they contain extensive operations and maintenance sections supplemented by filed acceptance criteria for certain types of defects found in service. The Code filed acceptance criterion for corrosion is known as B31G. Refinements to the concepts underlying B31G have led to two other methods used in the industry, the RSTRENG 0.85-area Method (sometimes referred to as the Modified B31G) and RSTRENG Effective Area Method.

All three criteria evolved from a corrosion assessment methodology developed for the Pipeline Research Committee (PRC) of the American Gas Association (AGA) in the early 1970's by Maxey and Kiefner to predict the failure stress level of a through-wall axial defect in pipe. This model referred to as the log-secant equation, is given by:

$$\frac{K_c{}^2\pi}{4L(\sigma^*)^2} = Ln\left[\sec\left(\frac{\pi M_T\sigma_T}{2\sigma^*}\right)\right]$$

Where σ_T is the nominal hoop stress at failure of a through-wall flaw, K_c is material toughness; L is the axial dimension of a through-wall defect; t is the pipe wall thickness; and D is the pipe outside diameter.

Certain simplifications were made to Kiefener and Maxey's original method in the development of B31G. The surface defect transformation was generalized in terms of metal area loss so that the nominal failure stress, S_f of a pipe with surface metal loss defect is determined by:

$$S_f = \sigma^*\left[\frac{1-\dfrac{A}{A_0}}{1-\dfrac{A}{A_0}/M_T}\right]$$

Where A is the cross sectional area of corrosion metal loss and A_0, the original area, is the product of axial length and the pipe wall thickness. It is assumed that the defect has a parabolic profile ($A = \frac{2}{3}dL$), reducing $\frac{A}{A_0}$ to $\frac{2}{3} \bullet \frac{d}{t}$. The flow stress of the pipe was approximated as 1.1xSMYS.

B31G was found to be sufficiently conservative that serviceable pipe was sometimes removed from service unnecessarily. Refinement of the B31G methodology to correct this problem led to two alternative assessment methods, the RSTRENG 0.85-Area Method, and the RSTRENG Effective Area Method. In both methods, the flow stress was redefined as S_y+10ksi, which, for line pipe steels is very close to the conventional fracture mechanics definition of flow stress as the average of the yield and ultimate strength, or $\frac{S_y + S_u}{2}$. The 3-term expression for M_T as originally proposed was reinstated. Both revisions reduce conservative errors in the estimated failure stress.

When only the axial length and maximum depth of corrosion are available, the 0.85-Area Method can be used to obtain generally more accurate predictions than those from B31G. The area of missing metal is represented by 0.85dL, reducing $\frac{A}{A_0}$ to $0.85\frac{d}{t}$. The 85 percent factor on area, which is more conservative than the parabolic profile assumption, was established on the basis of overall agreement with the behavior of long corrosion defects.

The Effective Area Method can be used if a detailed corrosion profile is available. This method determines the minimum failure stress level of all possible subsets of local area loss relative to surrounding metal I the corrosion profile.

Limitations of the Methodology:

All three variants of the corrosion assessment method of the reviewed herein were validated in plain carbon and low alloy steel pipe having strength and toughness properties and pipe dimensions that is reasonably representative of pipe in pressure service, at both low and high temperatures. They have been found to be reliable on smooth bends and weldments of reasonable quality and toughness, independent of fatigue considerations. The concepts are applicable to metal loss from internal corrosion or erosion as well, although greater attention must be given to characterizing the dimensions of the metal loss area if the defects are not visually accessible.

(Ref. 141)

Assessment of Long Corrosion Grooves in Line Pipe

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Various pipelines, coated with polyolefin tapes, have experienced corrosion damage due to disbondment of the tape. Disbondment and sagging or wrinkling of the tape can lead to the trapping of water between the pipe and tape. The resulting corrosion often has a longitudinal orientation due to the orientation of the wrinkles in the tape. There have been various methods developed to evaluation the significance of this corrosion: General approach of ASME B31G, CSA Z662 Clause 10.10.6 and RSTRENG, and the specific approach of Mok, Pick, Glover and Hoff. With exception of RSTRENG these assessment procedure approximate long corrosion as flat-bottomed grooves. If the depth of the corrosion varies or there is pitting, the depth of the groove is normally assumed to be the depth of the deepest pit. This leads to a conservative estimation of the burst pressure of the corroded pipe. RSTRENG will allow the geometry of the groove to be considered. However, RSTRENG tends to minimize the effect of individual pits whereas experiments show that burst normally originates in the deepest pit. Thus the RSTRENG produces an inconsistent factor of conservatism with different geometries.

In most jurisdictions, the B31G assessment procedure with variations is regulated as the assessment procedure. In Canada, CSA Z662 Clause 10.11 also allows an Engineering Critical Assessment using other established procedure or analysis techniques. Therefore, it is assumed that the initial assessment with long corrosion grooves will be undertaken using the B31G or CSA Z662 procedure. If this assessment procedure indicates an acceptable burst pressure no further assessment is required. If the predicted burst pressure is not acceptable it may indicate the pipe is unsafe or that the assessment procedure is overly conservative and an Engineering Critical Assessment is more applicable.

B31G: the assumption that the flow stress is 1.1 times the SMYS leads to a high degree of conservatism. Flow stress approximates based on the actual yield stress such as the yield stress plus 10 ksi are more appropriate.

Mok, Pick: Mok et al developed a model to predict the behavior of pipe with long defects in various orientations (spiral corrosion). This model was developed from burst tests on pipe with long flat-bottomed machined defects in spiral and longitudinal orientations. The equation developed by Mok et al to describe the strength of longitudinally oriented defects is shown:

$$P = 1.5P^{*}\left(1 - \frac{d}{t}\right)$$

Where P is predicted burst pressure of pipe with defect, P^* is predicted burst pressure of plain pipe and is approximated by $P^{*} = SMYS\frac{2t}{D}$. This is similar to the B31G formula except a factor of 1.5 is used based on consideration of the strain hardening behavior of a series of typical pipeline steels.

This assessment procedure is, on average, more accurate than B31G, but like B31G makes use of the deepest point in the corrosion as the depth of the flat-bottomed corrosion groove. This leads to a conservative prediction of the burst pressure of the pipe. If this is not acceptable a more accurate assessment procedure should be attempted.

RSTRENG: The RSTRENG assessment procedure allows the use of a more complete description of the longitudinal geometry of the corrosion compared to B31G and Mok. Et al. The main sources of conservatism in B31G were the assumed value of the flow stress and the simplification of the corrosion geometry. RSTRENG redefines the flow stress as the yield stress+10ksi and uses the actual corrosion geometry to describe the defect. An “effective area” technique is contained within the RSTRENG code that makes use of the variation in the depth of the corrosion in the longitudinal direction. These changes require more accurate measurement of the corrosion but reduce the conservatism in the assessment procedure compared to B31G and Mok et al.

Conclusions:

For the database of measured burst pressure B31G provides predictions of burst pressures that are 20% to 68% of the actual burst pressure. This technique is simple to apply, requiring the defect depth, length, pipe dimensions and grade of steel. Defects which meet this criteria are safe while defects which are calculated to be unsafe by B31G can be assessed with a less conservative method. The assessment method developed by Mok. For long corrosion is the least conservative of all methods when considering flat-bottomed grooves. However, this method is similar to B31G, although slightly less conservative, when applied to irregular bottomed longitudinal corrosion grooves since it does not account for pitting or variations in groove depth.

RSTRENG predicts failure pressures, which are 60% to 106% of the actual burst pressure when applied to the database. The prediction that is 6% above the actual failure pressure is for a defect that is 79% of the wall thickness deep. In general, the degree of conservatism associated with RSTRENG predictions decreased as the defect depth increased. Using a reduced wall RSTRENG analysis for long defects capture the corrosion geometry better but results in increased conservatism. This provides no benefit over a standard RESTRENG analysis.

(Ref. 284)

Analyzing the Pressure Strength of Corroded Line Pipe

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Current methods for evaluating the strength of corroded pipe are semi-empirical and limited t pressure loading alone. This paper describes finite-element results that are being used to develop a new method of evaluating corroded pipelines under axial and pressure loading. The results are compared to a database of over 80 burst tests. The comparison show that the pressure strength of corroded pipe can be more accurately predicted using the nominal membrane stress from the finite element analysis rather than using the nominal bending plus membrane stress. Also, failure in a region of corrosion occurs when the stresses in the corroded region are well over yield. So, as expected, failure involves plastic distortion and load redistribution, which depends on the size and depth of the corroded region.

B31G and its modifications consider internal pressure alone. These approaches work well in cases when pipelines are not subjected to high lateral or longitudinal movement or loads. However, for some pipelines, lateral or longitudinal movement or loads can be significant. When large axial and bending stresses are coupled with corrosion, the B31G estimates of pressure capacity may be unconservative.

(Ref. 247)

An alternative Approach to Assess the Integrity of corroded Line Pipe Part II: Alternative Criterion

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An alternative criterion based on an upper limit on failure pressure for very small defects and a lower limit that reflects large area defect is developed. This alternative criterion is termed "PCORRC", which is short for pipe corrosion failure criterion.

At present the alternative criterion for the failure pressure, P_F can be expressed as

$$P_F = UTS\left(\frac{2t}{D}\right)\left(1-\left(\frac{d}{t}\right)f(geometry)\right)$$

Term f(geometry) reflects the effects of defect length as a function of the pipe's cross-section geometry. Based on the present results, the transition between these has the form:

$$f(geometry) = 1-\exp c\left(\frac{L}{\sqrt{Rt_N}}\right)$$

Where C is a constant whose value is subjected to the bounds, it is about –0.16. UTS is the ultimate tensile stress.

The upper bounding limit for the function has the form:

$$P_F = UTS\left(\frac{2t}{D}\right)$$

The lower limit, which reflects the behavior of the large area patch where the failure pressure is proportional to the net-section wall thickness, is given:

$$P_F = UTS(\left(\frac{2t}{D}\right)\left(1-\left(\frac{d}{t}\right)\right)$$

It is emphasized that as written, PCORRC reflects failure by plastic collapse. If, for example, cracking due to either localized tearing or some brittle mechanism controlled failure as opposed to a shear instability, the use of PCORRC would lead to failure pressures that are no conservative. But this is to be expected as a consequence of using a failure criterion in an application where the active failure mechanism is not built into the criterion.

The key to implementing this alternative approach was developing functions of defect profile, size, and spacing that provide the transition between these upper and lower limits. Following verification of the alternative approach by its successful prediction of a range of defects, the functional dependence of failure pressure was demonstrated by its accurate and precise prediction of failure pressure for full scale covering a range of defect and pipe geometry.

(Ref. 172)

Bursting Of Line Pipe with Long External Corrosion

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Bursting of line pipe with infinitely long corrosion defects was simulated using the elastic plastic finite element method. Since elastic-plastic finite element analysis may not be readily available to many pipeline operators it is desirable to produce a simple evaluation technique that can be applied manually for long defects.

For the purpose of a convenient design equation it is reasonable to assume the burst pressure as:

$$P^* = 1.5(SMYS)\frac{t}{D}$$

Using this equation, the burst pressure of the plain pipe made of Grade 414 steel with outside radius of 254mm and wall thickness of 6.35mm was calculated to be 15.3 mpa. This compares favorably with the burst pressure of 15.445mpa measured in the burst test. The finite element analysis predicted a burst pressure of 16.6mpa but used the material properties which the yield stress considerable higher than the SMYS.

While this approach must be regarded as approximate, the user into the design equation will presumably incorporate a factor of safety. It would be convenient to include this factor of safety in the constant 1.5 suggested.

To consider the effect of the geometry of the corrosion groove it is necessary to predict the value of P/P^*. The finite element analysis indicated the P/P^* is primarily influenced by the groove depth d for longitudinal grooves and by the groove width w for circumferential grooves. For spiral both groove depth and width influence the P/P^* ratio.

As a basic definition of P/P^* the following is recommended:

$$\frac{P}{P^*} = \left[1 - Q\left(\frac{d}{t}\right)\right]$$

where P is the burst pressure of the corroded pipe, P^* is the burst pressure of plain pipe. D is the depth of the groove, t is the pipe thickness and Q is the spiral correction factor.

(Ref. 222)

Correction for Longitudinal Stress In the Assessment of Corroded Line Pipe

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Accurate assessment of the remaining strength of corroded line pipe is critical for pipeline operation in order to avoid both pipe failure and unnecessary pipe repair or replacement. Commonly used corrosion assessment techniques are ASME B31G, its Canadian equivalent CSA Z662 10.8.2 and RSTRENG. These assessment techniques assume that the burst of corroded pipe is governed only by the circumferential stress and therefore various conditions of longitudinal stress cannot be considered. In general, buried pressurized pipe has plane strain longitudinal conditions that produce a longitudinal stress equal to 0.3pr/t where p is the internal pressure, r is the nominal radius and t is the wall thickness and Poisson's ratio is 0.3. The assessment techniques were validated primarily by experiments on closed ended pipes that have a longitudinal stress equal to 0.5pr/t. Therefore under normal conditions the assessment techniques are expected to be applicable. However, additional longitudinal stress can be generated by temperature changes and bending moments. In this situation the assessment prediction of burst pressure may not be as conservative as expected.

Chouchaoui and Pick showed that open ended burst pressure were on average 18% lower than closed ended burst pressure. Grigory and Smith found that burst failure were predominately on the compression side of the pipe I bending for similar corrosion defects on both the tensile and compressive side of the pipe. Also when bending and longitudinal loads were combined to provided tension on one side of the pipe and zero stress on the other side, failure occurred on the tensile side of the pipe rather than the unstressed side. Thus either compressive or tensile longitudinal stress relative to some datum appeared to decrease the residual strength of corroded line pipe.

Correction to Assessment Procedures for Longitudinal Stress:

Assessment procedure such as B31G and RSTRENG have generally been validate against close-ended burst test results. This condition produces the maximum burst pressure and other longitudinal stress conditions will have lower burst pressures. However, in normal pipeline operating conditions of plane strain the difference is very small. In situations where thermal stress or bending stress occurs, a correction for longitudinal stress that can be applied to current assessment procedures would be useful. A longitudinal stress factor LS is developed from simplified principles.

The longitudinal stress factor LS is defined as:

$$LS = \frac{0.866 * D}{\sqrt{C^2 - C + 0.25 + 0.75 * D^2}}$$

Where C is load factor and D is Defect Effect Ratio.

$$C = \frac{\sigma_{long\_a}}{\sigma_{circ}}$$

$$D = \frac{failure\ pressure\ prediction\ for\ pipe\ without\ a\ defect}{failure\ pressure\ prediction\ for\ pipe\ with\ a\ defect}$$

D can be calculated using B31G or RSTRENG with and without a defect. A small defect will have a value of D close to unity, and a larger defect will have a value greater than one.

The corrected failure pressure P_{B_LS} that considers the effect of longitudinal stress on the pressurized corroded pipe can be calculated as:

$$P_{B\_LS} = P_{B\_CAT} * LS$$

where P_{B_LS}=modified burst pressure prediction, P_{B_CAT}=burst pressure prediction for a pipe with a defect using current assessment techniques.

(Ref. 140)

New Procedures for the Residual Strength Assessment of Corroded Pipe Subjected to Combined Loads

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The new methodology has been incorporated in the personal computer based program SAFE (Shell Analysis Failure Envelop) developed by Southwest Research Institute (SwRI) for the Alyeska Pipeline Service Company. The user-friendly program allows for definition of combined applied stresses and geometry of the degraded region through implementation of filed-obtainable pre- or post-excavation measurements, and employs unique features which provide for the examination of pipe section exhibiting distinct areas of general corrosion, or "patches", separated both longitudinally and circumferentially, in a single analysis run.

The safe application of any assessment procedure requires that the residual strength prediction for the observed damage and applied loads be reliable and no more than mildly conservative. The assessment procedure described herein provides a theoretical sound technology suitable for use in service condition that reflect combined loading to predict failure pressure and curvature for a pipe having a discrete metal loss region with a minimal amount of conservatism.

Two dominant failure modes were identified in the supporting experiments and numerical modeling studies: 1) A local failure mode-rupture, and 2) a global failure mode – bending collapse. Axial collapse corresponds to buckling of the pipe as a column primarily due to large axially compressive loads. It is unrealistic to predict axial collapse for buried pipe. Thus, the engineering model directly considered only two failure criteria.

The rupture criterion involves a von Mises type prediction of failure with non-zero hoop and axial stresses. The bending collapse criterion, which was deemed a less critical condition than rupture, was derived from the database of experimental simulations and parametric analysis indicating a bending collapse failure. The engineering model was then incorporated into SAFE to permit the determination of safety margins for given service conditions of operating pressure, bending moment, and axial loading due to restrained thermal expansion as a function of corrosion dimensions obtained from pre- or post- excavation of the pipe.

Rupture Failure Mode:

Using an elastic shell theory approach to address rupture failure resulting from local plastic instability in a corrosion patch under combined loading, the following stress based failure criterion von Mises type is applied:

$$\sigma_\theta{}^2 - \sigma_\theta \sigma_x + \sigma_x{}^2 = (k\sigma_0)^2$$

where σ_θ is the pipe hoop stress, σ_x is the pipe axial stress, σ_0 is the maximum true stress of the X65 Steel, and k represents an amplification factor applied to reduce conservatism inherent in the elastic approach. $k\sigma_0$ is denoted as the von Mises limit stress.

Hoop Stress Relation

$$\sigma_\theta = \frac{PD_n}{2t_0}\left(\frac{1-\left(\frac{d}{t_0}\right)B}{1-\left(\frac{d}{t_0}\right)}\right)$$

Axial Stress Relation

$$\sigma_x = A_x\frac{\upsilon PD_n}{2t_0} - A_x\alpha_t E\Delta T \pm \frac{M}{Z}$$

$A_x = \left(1-\frac{\frac{1}{2}\alpha_\rho\beta\left(r_0^{\ 2}-r_c^{\ 2}\right)}{\pi\left(r_0^{\ 2}-r_j^{\ 2}\right)}\right)^{-1}$ is the axial stress amplification due to the reduction of area in the corrosion zone.

Rupture Criterion

Substituting the hoop and axial stresses into the von Mises type failure criterion gives the rupture failure criterion in terms of the internal pressure and the total bending moment.

$$\begin{aligned}(k\sigma_0)^2 = &\left(\frac{PD}{2t_0}\right)^2\left[F^2-\upsilon A_x F+\upsilon^2 A_x^{\ 2}\right] \\ &\left(\frac{PD_n}{2t_0}\right)\left[2\upsilon A_x - F\right]\left(\pm\frac{M}{Z}-A_x\alpha_t E\Delta T\right) \\ &\left(\frac{M}{Z}\right)^2 + \left(A_x\alpha_t E\Delta T\right)^2 \pm 2\frac{M}{Z}A_x\alpha_t E\Delta T\end{aligned}$$

where F is equal to:

$$F = \frac{1-(d/t_0)B}{1-(d/t_0)}$$

(Ref. 306)

Interpretation of Metal Loss as Repair or Replace During Pipeline Girth Welds

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A three tier methodology for the assessment of metal loss defects in pipes under internal pressure loading. Assessment procedure is similar to the B31G but incorporates explicit safety factors to account for possible inaccuracies in the assessment method and for uncertainties in the pipeline operations. The procedure is as:

$$P_0 = SFxSMxP_f$$

where P_0 is the maximum operating pressure, P_f is the failure pressure, SF is the safety factor and SM is the safety margin related to the pipeline codes.

The failure pressure, P_f is estimated using the following formulation:

$$\sigma_{hf} = \left[\frac{1-d/t}{1-(d/t)M^{-1}}\right] = \frac{P_f R}{t}$$

$$M = \left[1 + 0.4\left(\frac{2c}{\sqrt{Rt}}\right)^2\right]^{1/2}$$

where σ_{hf} is the pipe hoop stress at failure, σ_f is the flow stress taken here as 1.15 times σ_y (SMYS).

For defects assumed to have an infinite length, the above equation becomes:

$$\sigma_{hf} = \sigma_f(1-\frac{d}{t}) = \frac{P_f R}{t}$$

Safety factor is taken as 0.97 and safety margin is 0.72.

The proposed methodology allows metal loss defects to be assessed using a simple conservative criterion, a more detailed accurate criterion or a specialist advanced approach.

Tier 1:

Defects of maximum depth, d, are assumed to have infinite length and are assessed using the equation:

$$P_0 = 0.97 \times 0.72 \times [1.15SMYS(1-d/t)t/R = 0.8SMYS \times t/R(1-d/t)]$$

Tier 2:

Defects of maximum depth d and maximum length 2c are assessed using the equation:

$$P_0 = 0.8SMYS\frac{t}{R}\left[\frac{1-d/t}{1-(d/t)M^{-1}}\right]$$

Tier 3:

The operator, who is responsible for producing evidence of the safety and reliability of the adopted analysis, chooses the assessment method at this level.

(Ref. 223)

A New Rupture Prediction Model for Corroded Pipeline under Combined Loading

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A new strain based rupture prediction model is developed for buried corroded pipes subjected to internal pressure, lateral bending, thermal loading and residual stress. Models that apply to pipes subjected to combined pressure, bending and axial loading are rare. Under combined pressure and bending, the existing models usually employ a failure locus in the pressure and moment space. This approach implies that under dead loading, bending will reduce the pressure at rupture. However, this need not be the case in the field where displacement controlled bending and axial loading are induced by differential settlement and axial constraint. Axial stresses within the corroded region due to bending and thermal expansion decrease to nearly zero at rupture provided sufficient strain capacity in the material exists. This implication is that the rupture pressure of a corroded pipe under combined pressure and fixed displacement secondary loading is the same as that for a pipe under internal pressure, only if sufficient strain capacity exists.

Rupture Mechanism:

Under combined internal pressure P and axial bending moment M, failure in an extensive corrosion patch of a pipe due to excessive ductile straining may be expressed by the von Mises yield criterion.

$$\frac{3}{4}\sigma_\theta^2 + \sigma_b^2 = \sigma_0^2$$

where σ_θ is the hoop stress due to pressure, σ_b is the axial bending stress in the patch, and σ_0 is the maximum allowable stress for the material.

Two different types of failure modes can occur depending upon how the bending moment is transmitted to the corroded pipe. If a fixed bending moment M_0 is first applied to the section containing the corrosion patch, the path is followed during subsequent pressurization, with ductile rupture occurred at B with failure pressure P_f. Clearly, in the case the failure pressure depends upon the applied moment M_0. However, if the moment M_0 is produced by settlement of the pipe such that its curvature remains fixed during pressurization, the first part of the path to failure remains unchanged from that for a fixed moment. The thinned area can withstand further pressure beyond point B for a fixed curvature because the bending compliance increases with further plastic straining. Consequently, the bending stresses will decrease to accommodate the greater hoop stress necessary to balance the increased pressure and satisfy the failure criterion. While there will be no further increase in the axial strain, the hoop strain will increase at the expense of wall thickness. For a material with unlimited strain capacity, failure will occur at point where bending stress vanishes. The sam e phenomenon will occur for other fixed-displacement loading that are generally characterized as self-equilibrating stresses fields. While these stress fields will influence yielding, they do not impact the ductile failure because the compliance of the structure becomes unbounded and these self-equilibrating stresses vanish as the ductile failure point is approached.

For the strain based rupture prediction model, if the hoop strain exceeds its allowable limit, the pipe is considered to have ruptured. Hoop strain, instead of total effective strain, is used as the strain measure, since the axial strain does not change significantly for a buried pipe before rupture due to the near plane strain condition in the longitudinal direction.

The ductile rupture pressure (P_f) for extensive reduces in this case to

$$P_f = \frac{2}{\sqrt{3}} \frac{\sigma^{ult} t^*}{R} \frac{1}{B}$$

where t^* is the net thickness of the corroded region, R is the mean radius of the pipe, σ^{ult} is the material's ultimate strength, and B is "Bulging factor". In the current model, thermal stress, initial pressure, bending and final pressure are applied sequentially. A simple relation is used in the current model. That is,

$$P_f = \frac{\sigma^{ult} t}{R} \left\{ 1 - \frac{d}{t} \left[1 - \exp\left(-c \frac{L}{\sqrt{Rt^*}} \right) \right] \right\}$$

$$c = 0.173$$

(Ref. 31)

Reliability-Based Limit State Design and Re-Qualification of Pipeline

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The paper presents reliability methods and their applications to limit state design and re-qualification of offshore pipelines.

A Design Through Analysis approach has been developed by Bai and Damsleth where the finite element method is used to analyses global behavior as well as local structural strength of pipelines. The structural reliability method is used to determine the partial safety factors used in the finite element analysis.

Fracture Reliability of Dented Pipe with Cracks

Mechanical damages such as dents and cracks occur to pipelines frequently mainly caused by third party activities and fabrication errors. With a combination of extremely large defect and low fracture toughness , the fracture failure mode may become critical. A design equation for dented pipes with cracks can be formulated as

$$g(Z) = 2\frac{t}{D} \bullet \frac{2\sigma_p}{\pi} \cos^{-1}\left(\exp\left(-\frac{\pi K_{mat}^2}{Y^2 8a\sigma_p^2} \right) \right) - P_L$$

Where Z is a set of random variables involved in the new design format; K_{mat} is material toughness; σ_p is the collapse stress for an infinitely long pipe defect having a notch depth a; Y is geometry function; P_L is the characteristic load (Internal pressure). Corresponding safety factor for design and assessment is calibrated based on reliability methods.

It is interesting to note that D_d/t is a key factor affecting pipe fracture strength, since the stress concentration in the defect is proportional to the dent depth. It also observed that the ratio a/t is quite influential to fracture reliability. As the crack depth increase, the reliability decreases rapidly.

If no calibration is conducted, the safety factor usually taken as 2.0, which corresponds to a safety level β=3.926. Based on reliability calibration, the new calibrated safety factor is 1.89 and 1.62 for target reliability levels of 10^{-4} and 10^{-3} respectively.

OMAE 1998 (Ref. 86)

Driving Force and Failure Assessment Diagram Methods for Defect Assessment

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A number of procedures have been developed for performing a fitness-for-purpose assessment of a defective component. The results of such an assessment may be presented in terms of a parameter, such as crack opening displacement or J-integral, describing the driving force on the crack tip, which is compared with the material resistance to cracking. An alternative representation is in terms of a failure assessment diagram where a point on the diagram represents the state of a defective structure; failure is then avoided if the point lies within a bounding curve.

Crack Driving Force Method:

Existing fitness-for-purpose procedures represent the crack driving force in term of either the crack opening displacement (COD) or the J-integral, which characterizes the state of stress and strain near the crack tip.

Engineering Treatment Model (ETM) developed in Germany. To use ETM method, the total strain in the plastic portion of the stress-strain curve should be represented by a power law,

$$\sigma / \sigma_Y = (\varepsilon / \Delta\varepsilon)^N$$

where N is a constant. When the material is expected to exhibit a Luders plateau, then

$$J = J_0 \left[1 + \frac{1}{2} \left(\frac{F}{F_Y} \right)^2 \right] \text{ for } F<F_Y$$

It is apparent that once the material has been described by the above equation, the ETM method enables J to be easily estimated from calculations of only the elastic stress intensity factor and the yield load.

Failure Assessment Diagram Methods

The R6 procedure requires the calculations of two parameters. The first of these is K_r, a measure of proximity to elastic fracture, which is defined by

$$K_r = K(a,F) / Kmat$$

K_{mat} is the fracture toughness of the material.

The second R6 parameter, L_r is a measure of proximity to plastic collapse:

$$L_r = F / F_Y$$

Having calculated K_r and L_r, the point (L_r, K_r) is plotted on a failure assessment diagram, which is bounded by a failure assessment curve.

$$K_r = f(L_r)$$

and a cut-off

$$L_r = L_r^{\max} = \sigma_f / \sigma_Y$$

Provided the point (L_r, K_r) lies within the region bounded by the curve and the cut off, fracture is avoid; otherwise failure is conceded.

Although the ETM and FAD methods appear different, it transpires that they can be made compatible provided the failure assessment curve is related to the equation used to estimate J. the compatibility is possible because the basic calculations required in both methods are the elastic stress intensity factor and the limit load and is briefly set out in this section.

(Ref. 50)

Criteria for Dent Acceptability in Offshore Pipeline

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The paper discusses testing and analysis work done to establish the effects of pipeline dents (without gouge) under cyclic internal pressure loading. The results indicated that plain smooth dents less than 5% of the diameter for pipe with a diameter to thickness of less than 30 are not a problem for normal pipeline service. Plain dents are probably not a concern for normal gas line service. An analytical procedure was developed to predict the fatigue life of a pipeline subjected to a combination of plain dents and cyclic pressure.

Fatigue Analysis:

The equivalent number of cycles for a pressure range from 0-1200 psi were calculated by the use of Miner's rule and by assuming the Fatigue curve has the form:

$$N = \frac{C}{S^{3.74}}$$

where N=equivalent number of cycles, C=2.0E+6 cycles, S =Stress which is assumed linear with pressure.

The S-N fatigue curve first used for this analysis was API_RP2A curve X' with:

$$N = C\left(\frac{\Delta\sigma}{\Delta\sigma_{ref}}\right)$$

Endurance limit at 200 million cycles =3330psi. Where N = Fatigue life in cycles, C=2.0E+06 cycles, $\Delta\sigma$= pressure fluctuation, $\Delta\sigma_{ref}$ = 11400psi, m=3.74. The Miner's rule was used to derive a linear damage factor since the pressure and stress amplitudes vary widely. The assumption made is that the application of n_i cycles at a stress amplitude $\Delta\sigma_{I,}$ for which the average number of cycles to failure is $N_{i,}$ cause an amount of fatigue damage that is measured by the cumulative cycles ratio n_i/N_i. Therefore, the estimated fatigue life X can be calculated as:

$$X = \frac{1}{\sum \frac{n_i}{N_i}}$$

It should be noted that n_i has to be the estimated cycles/year for the fatigue life, X, to be in year.

The study, so far, shows that computing the fatigue life of the pipeline based on the API-X' S-N curve is too conservative.

(Ref. 269)

Fatigue Life of Pipelines with Dents and Gouges Subjected to Cyclic Internal Pressure

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The order of severity when considering defects in pipes are listed as

1. Defect (gouges) in a dent
2. Dent in a weld seam
3. Plain dent, 4% (d/D)
4. Plain dent, 2% (d/D)
5. Plain defect

The literature review and discussions with other researchers indicated that the defining characteristic which makes the dent/gouge combination so dangerous is the presence of micro cracks at the base of the gouge. Research indicated that the most effective method of testing was to create a gouge first and then place a dent in the gouges region. Gouges in the pipe were installed in the pipe by a local machine shop. The most reproducible micro cracks were made from a machined groove with an 0.002" radius.

Experiment Results:

Pipe #2 was developed to study the effects of gouges with and without dents and the effects associated with the repair method of grinding the gouge out of the pipe.

a. Gouge depth has a significant impact on the fatigue life of a pipe. It was found that a gouge depth of 5% (with no grinding) has a fatigue life which is three and a half times greater than a 15% gouge depth.
b. Fatigue life was increased significantly when grinding was applied as a means of repair. The gouges which were ground had fatigue lives which were at least three times greater than non-ground counterparts. Also note that the cyclic pressure variation had a significant impact on fatigue life in that a pressure variation causes at least 10 times as much fatigue damage per cycle.
c. The results indicate that the gouges without dents had the longest fatigue lives.

Pile #3 was designed to study the effects of dents (without gauges) in conjunction with both longitudinal and girth welds.

a. It would seem that girth welds have a greater impact when considering reduction in fatigue life than do longitudinal welds.
b. Plain dents have longer fatigue lives when not combined with gouges. It demonstrated that gouges have the effect of seriously reducing the fatigue lives of piles and dents.

Pipe #1 was designed to determine what effect gouges and welds have no the fatigue life of pipes with plain dents.

a. The processing of grinding out the gouges was found to increase fatigue life significantly.
b. The gouges with no dents had the longest fatigue lives and the process of grinding does not appear to significantly increase the fatigue lives of gouges, which do not have dents.

Finite Element and Fatigue Analysis:

The objectives of this process were to develop a procedure for determining fatigue life of pipes with plain dents using stress intensification factors based on the finite element work. Elastic-plastic analysis was found to be the most useful means for determining accurate $\Delta\sigma/\Delta P$ values and for modeling the dent removal phenomena using finite elements.

Conclusions:

a. Plain dents as a stress concentration factor for cyclic pressure. For small D/t pipe, this SCF can be as high as 5. For lower d/t, a maximum SCF of 3 or less results because of cyclic plasticity and shape changes of the dents. The SCF is very heavily dependent on the dent depths, but not dependent on the dent shape. The maximum SCF's occur with the largest dents.
b. Fatigue analysis with conventional fatigue analysis procedures for dents without gouge under cyclic pressure is mostly satisfactory and conservative.
c. Gouges combined with dents can be very dangerous under cyclic pressure loading. Gouges are dangerous because of micro cracks, which form as a dent/gouge is made. This micro cracks eliminate a large portion of the fatigue crack growth process and are the reason that the fatigue life is low.

(Ref. 35)

A limit State Approach to the Design of Pipelines for Mechanical Damage

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Pipelines are currently designed to resist mechanical damage forces by using an indirect method that increase the thickness required for pressure design by a factor related to population density. This is achieved by specifying the use of more conservative pressure design factor in highly populated areas, which are perceived to have a high incidence of such damage events.

Currently, no generally accepted design procedures are available for directly designing pipelines for concentrated outside forces. A number of researchers have conducted experimental and analytical work and some have proceeded to develop puncture resistance equations, but none of these methods has thus far been incorporated into a pipeline design standards.

Many existing design standards use an indirect method that increases the pipe wall thickness required by the internal pressure design for area with larger population densities. This results in a greater resistance to outside force damage in areas where there is a greater likelihood of excavation activity and where the consequences of failure are more severe based on the number of persons exposed. The disadvantage of this approach is that it can produce unnecessary increase in pipe wall thickness for large diameter pipelines that may already have sufficient wall thickness for large diameter pipelines to resist outside force damage, and can produce insufficient increases in wall thickness for small diameter pipelines.

Although the current indirect design method has apparently served industry well, designing directly for accidental outside force damage would seem to be a more rational approach and should lead to more uniform reliabilities. A direct limit states design method should allow adequate pipeline resistance to be achieve without excessive conservatism.

Limit States Design Procedure

Limit states design (LSD) is a semi-probabilistic design process that uses partial safety factors (Load and Resistance Factors), determined via reliability analyses, to ensure that an acceptably low probability of failure is achieved for all design cases to which the partial safety factors apply. It is a practical means of incorporating reliability method in the normal design process.

The limit states design equation for mechanical damage from an excavator tooth can be written as:

$$\phi\left\{0.8\left[1.17-0.0029\left(\frac{D}{t}\right)\right](L+w)tF_u/100\right\}-\alpha\, Q=0$$

In order to determine appropriate partial factors for design, a reliability analysis was undertaken using the statistical values for each variable. Eight design cases were considered corresponding to the various combinations for values of D, t, and F_u near the low and upper limits of the ranges for which the design equation has been validated.

The foregoing analysis leads to a limit states design procedure for directly designing pipelines to resist accidental outside forces that might be applied by the bucket of an excavator. The resistance term becomes:

$$\phi\ R_p = \phi\left[70.2 - 0.174\left(\frac{D}{t}\right)\right] tF_u / 1000$$

the load term is represented by:

$$\alpha\ Q = 260\varepsilon$$

The resulting design equation is:

$$260\alpha \le \phi\left[70.2 - 0.174\left(\frac{D}{t}\right)\right] t\left(k_t F_u\right)/1000$$

(Ref. 171)

Recent Studies of the Significance of Mechanical Damage in Pipelines

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The paper briefly summaries early British Gas studies on the effect of combined dents and defects on transmission pipelines and reports recent studies on the failure of this type of defect.

The British Gas Studies on the effect of dent and defects have coved:

a. Straight-off to failure tests and analysis
b. Fatigue test
c. Time dependent failure
d. Crack growth in dents with increasing pressure
e. Effect of introducing damage into pressurized pipe.

Failure Tests:

Experiments over recent years have confirmed that failure is significantly affected by: Dent depth, gouge depth and ductile fracture resistance. The failure relationship to be defined as:

$$\frac{\sigma_f}{SMYS} = \frac{C_v}{10^3}\left[15.35 - 0.71\left(\frac{d}{t}\right) - 0.17\left(\frac{2R}{D}\right) + 0.09\left(\frac{2R}{D}\cdot\frac{t}{d}\right)\right]$$

C_v = 2/3 Charpy Energy, σ_f = predicted failure stress, SMYS = Specified Minimum Yield Stress if Pipe, d/t = defect depth/wall thickness, d/2R = dent depth/Pipe diameter.